Reliability Assessment

1999–2008

The Reliability of

Bulk Electric Systems

in North America

North American Electric Reliability Council

May 2000

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.

> The NERC Reliability Assessments are normally published in September each year. However, publication of this report was delayed, in part, to include the announced merchant generation additions in the analysis.

This *Reliability Assessment 1999–2008* report presents:

- an assessment of electric generation and transmission reliability through 2008,
- an assessment of the generation resource adequacy of each Interconnection in North America,
- a discussion of key issues affecting reliability of future electric supply, and
- Regional assessments of electric supply reliability, including issues of specific Regional concern.

This report reflects the expertise, judgment, and interpretations of the RAS members. 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 January 1, 1999. Detailed background data are available in NERC's *Electricity Supply & Demand* (ES&D) database, 1999 edition.

Generation Data Projections

The majority of new generation additions over the next few years are expected to be constructed by the rapidly growing merchant generation industry. NERC's generation data collection procedures only capture that capacity for the analysis if its output has been sold to a reporting load serving entity. Therefore, many of the new merchant generators may not be reported to NERC.

Information on announced merchant generation capacity additions is compiled by the Electric Power Supply Association (EPSA). Although new generation announcements are made daily and more updated information was available at the time of this publication, EPSA data made available as of September 1, 1999 was used in this report to be more consistent with the demand forecasts of January 1, 1999 used in this report.

Interconnection Analysis

This year's report includes generation resource adequacy analyses of the electric systems in North America on an Interconnection basis. For purposes of this report, an Interconnection is defined as one of the three major electric system networks in North America, each of which operate synchronously and independently, and which is connected to another Interconnection by direct current ties. These Interconnections include the Eastern, Western, and ERCOT Interconnections.

Assessment Time Frame

RAS views this ten-year assessment in two time frames: the near term, consisting of the next three to five years and the long term, which is the balance of the ten-year assessment period. 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 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.

Starting with its 1999 data collection, the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE) began collecting data for five future years instead of the traditional ten years. However, the NERC Engineering Committee (now the Adequacy Committee) directed the RAS to continue to collect data on a ten-year basis to help identify trends in demand and energy forecasts.

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, standards, principles, and guides, and assesses the future reliability of the bulk electric systems.

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 Norté, 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.

NERC in Transition

NERC is in the process of transforming itself into a self-regulatory reliability organization (SRRO) that will have the responsibility and authority to set and enforce compliance with mandatory standards for the bulk electric system that apply throughout North America.

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. There has been a marked increase in the number and seriousness of violations of voluntary reliability rules. 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. This past summer, the actions of certain control areas in the Eastern Interconnection clearly demonstrated the inadequacy of the existing arrangement.

Little or no effective recourse exists today under the current voluntary model to correct such behavior. No single bulk power system reliability standard can be enforced effectively today by NERC or the Federal Energy Regulatory Commission (FERC). FERC is being asked to make decisions on reliability issues for which it lacks both the technical expertise and clear statutory authority. One-third of the nation's transmission facilities are beyond FERC's jurisdiction.

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 Electric Reliability Organization (ERO) to develop and enforce mandatory reliability rules with FERC oversight in the United States to make sure the ERO 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).

Many measures are now pending in the House and Senate incorporating the NERC consensus legislative language. To ensure that the reliability of the transmission grid is maintained as the electricity marketplace becomes more competitive, it is imperative that Congress approves reliability legislation as soon as possible. Even after enactment of reliability legislation, it will take some time to complete the necessary rule making and gain the required approvals before the ERO can actually begin operation. The longer it takes to establish this new system, the greater becomes the risk and magnitude of grid failures.

EXECUTIVE SUMMARY

Near Term

Near-term reliability is dependent on merchant capacity additions. Reported summer capacity margins for 1999 through 2003 are at the lowest levels in many years, particularly in the Eastern Interconnection. However, those margins do not reflect all of the proposed merchant generation capacity additions announced for construction during that period because that data was unavailable when the margins were calculated. Plans have been announced for construction of about 51,600 MW of merchant generation by the end of 2001. By the summer of 2001, demand is projected to grow by about 27,500 MW. More than half of the announced generation will be needed just to keep pace with demand growth in the next two years.

Without the announced new generation capacity, capacity margins could be dangerously low, challenging the ability of the bulk electric supply systems in the Eastern Interconnection to respond to higher-than-projected customer demand caused by extreme weather and unexpected equipment shutdowns or outages.

Growing reliance on demand diversity. The near-term scarcity of generation capacity is resulting in a growing reliance on demand diversity. During the summer of 1999, Regions in the Eastern Interconnection were projecting to purchase about 13,700 MW more capacity than was projected to be sold or that can be physically imported from the Western and ERCOT Interconnections on the high-voltage, direct current ties. That represents about 2.3% of the installed generating capacity of the Eastern Interconnection. If sufficient demand diversity does not exist at the time of peak, or if there is insufficient transfer capability between the Interconnections and the Regions to move the available capacity where and when needed, some areas of the Interconnection could experience capacity shortfalls. These supply and demand conditions logically could also result in price spikes for the available wholesale power.

Additional voltage support needed for transmission system. More attention needs to be paid to the reactive needs of the transmission system. Reactive power needs are growing ever more important as the collective use of the transmission system increases. Voltage problems in ECAR, SERC, and MAAC experienced during the 1999 summer peak demands and heavy transfers indicate that reactive support enhancements are needed to the transmission system to maintain adequate voltage and prevent voltage instability. Summer peak demands are becoming largely driven by air conditioning, which tends to draw significant amounts of reactive power from the electric system. Distribution systems must keep pace with reactive capacity additions to compensate for and be responsive to the increasing reactive demand on the system.

Similarly, transmission owners must be able to supply adequate reactive power to maintain voltage stability during heavy transfers of electricity, regardless of the local demand level at the time of the transfers. Indications are that backup reactive power supplies are also needed to replace the reactive power lost when key generating units are forced out of service. This reactive power support must be versatile enough to support a multitude of directions of transfers being fostered by open access transfers.

System operators and security coordinators increasingly challenged to meet the needs of evolving competitive electricity markets. Market-driven changes in transmission usage patterns and the number and complexity of transactions are causing new transmission limitations to appear in different and unexpected locations. Continued over-subscription of the transmission network's capabilities is resulting in the need to invoke transmission loading relief (TLR) procedures more frequently. Other methods of congestion management, such as market-based redispatch of generation are being investigated, and long-term solutions are being sought.

Additional data exchange and analytical tools will go on line by summer 2000 to assist the operators with managing transactions. Work also is proceeding to improve the calculation and coordination of Available Transfer Capability (ATC). Regional standards are under development for calculation of Transmission Reliability Margin (TRM) and Capacity Benefit Margin (CBM).

Outage coordination and sufficient lead times may be necessary to mitigate potential near-term effects of NO_x regulations on resource adequacy. To comply with nitrogen oxide (NO_x) regulations promulgated by the U.S. Environmental Protection Agency (EPA), outages of significant amounts of fossil-fueled generation will be necessary over the next few years to install the required NO_x control devices. The RAS directed a study of the potential reliability impacts of those retrofit outages on near-term resource adequacy. Results indicate that increased outage coordination in the Regions and the length of the retrofit window will be important factors in mitigating potential reliability impacts. Final results are contained in a separate report, "Reliability Impacts of the EPA NO_x SIP Call," issued by the RAS, available at: http://www.nerc.com/~filez/ras.html.

Based on the results of the analyses, it logically follows that any reduction in the amount of Selective Catalytic Reduction (SCR) equipment needed for compliance, or an extension of the retrofit window, will lessen the adverse impacts of the NO_x SIP Call. Application of alternative NO_x reduction technologies (that do not require additional generation outage time for retrofits) might also reduce the number of units requiring SCR equipment, thereby reducing the impact of retrofits. Similarly, use of State Supplemental Allowance Credits, proposed by the EPA, could effectively extend the retrofit window, again reducing the SIP Call impacts on near-term adequacy.

Long Term

Electric supply adequacy will require the long-term development of additional generating and transmission capacity to keep pace with growing customer demand and changes in transmission use patterns driven by industry restructuring and market forces. NERC's responsibility is to report and assess resource and demand data. Ultimately, the individual systems and the open market are responsible for providing adequate resources to meet the demands of electric customers. Merchant generation developers are responding to market signals and new plants are under construction in many areas. Plans for significant additional merchant capacity are being announced almost daily in a number of Regions.

Customer Demand is continuing to grow:

- **Actual growth higher than projections** — Actual demand growth rates experienced over the last few years are significantly higher than the current projections.
- **Strong economy continues to drive growth** — A strong economy in North America is continuing to drive demand and energy to grow faster than projected.

Very few bulk transmission line additions planned. Only 6,978 miles of new transmission (230 kV and above) are planned throughout North America over the next ten years. This represents only a 3.5% increase in circuit miles, but an increase of about 400 circuit miles over last year's projection. The majority of the proposed transmission projects are for local system support. It is yet unclear if appropriate incentives exist to prompt transmission system additions and reinforcements to support the needs of a competitive energy market. New regional planning entities, adequate pricing incentives, and improved, streamlined approval processes also must be developed to deal with the need for new transmission lines for an open market.

As the demand on the transmission system continues to rise, the ability to deliver energy from remote resources to demand centers is deteriorating. New transmission limitations are appearing in different and unexpected locations as the generation patterns shift to accommodate market-driven energy transactions, and the connection of new, market-responsive merchant capacity that was not considered at the time the transmission system was designed. Delivering energy to deficient areas in any direction and amount that market forces desire is difficult.

Long-term reactive planning needed. The ability to transfer energy across some interfaces is at times being hampered by insufficient reactive power support. Low voltages experienced during the summer of 1999 highlighted this problem. It is imperative that reactive support enhancements keep pace with the demands being placed on the transmission system to maintain reliability. Distribution systems also must maintain adequate reactive power support to keep air conditioning and other inductive demands from creating voltage problems on the transmission system. Reactive power support must be planned and coordinated between transmission and distribution. To accommodate the widely varying flow patterns and associated reactive demands that have become commonplace with open access transmission use, the reactive support systems also must be far more versatile.

Coordination of merchant generation and transmission plans a must for continued reliability. The close coordination of generation and transmission planning that resulted in the highly reliable electric system of North America must now be accomplished in different ways by many entities. Market demand signals will drive the distribution and timing of generation capacity additions, and also should contribute to planning for the needed transmission capacity additions. When integrating new generation, the associated transmission additions and reinforcements must be designed and coordinated with other generation and transmission additions, and then constructed before the generation can be placed in service to ensure reliability.

Definition of Reliability

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

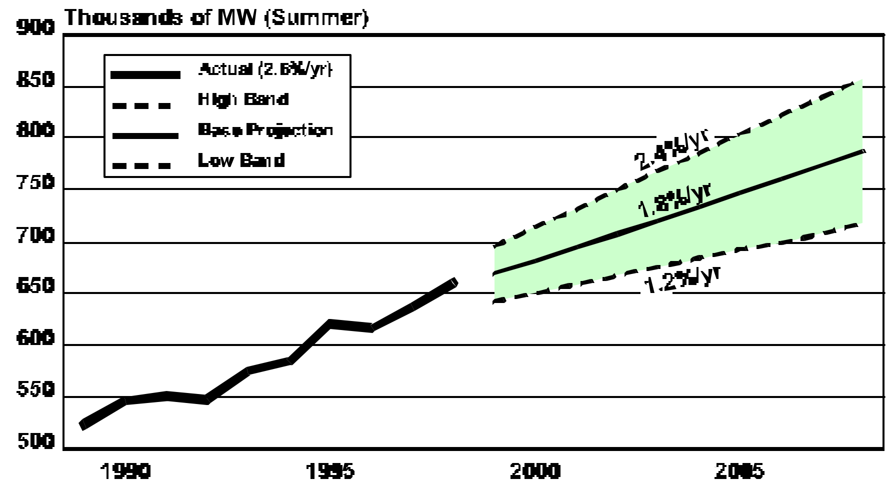
1. Adequacy — The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
2. Security — The ability of the electric system to withstand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

Demands and Resources

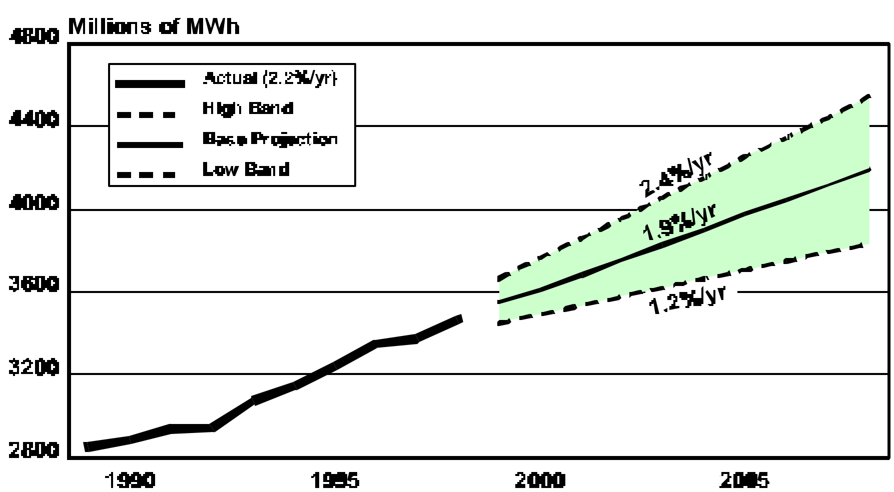
The average annual peak demand growth over the next ten years is projected to be a relatively modest 1.8% for demand and 1.9% for energy use in the United States (Figure 1). The projected growth in demand is similar to the projections of the last several years, but the 1.9% growth in energy is above last year's projection of 1.7% per year. Both projections are substantially below the actual growth rates experienced over the last ten years. High and low bands around the base forecast show a range of the forecast uncertainty.

Figure 1

United States Peak Demand
1999-2008 Projection



United States Net Energy for Load
1999-2008 Projection



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. This means that a 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 are 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.

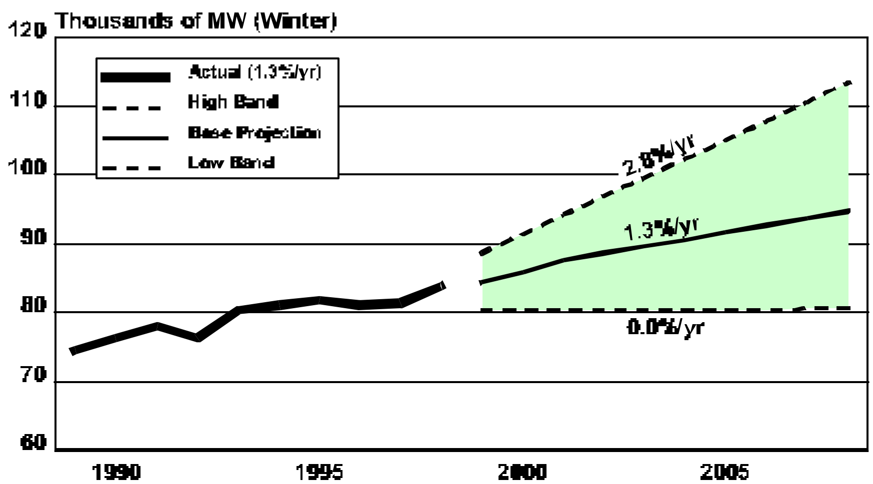
Uncertainty in the demand forecast has shifted and increased slightly the range of the bandwidths, projected by the NERC Load Forecasting Working Group (LFWG), from 1.4 to 2.3% last year to 1.2 to 2.4% this year. Similar increases in energy growth rate uncertainty are reflected in the shifted bandwidth range from 1.2 to 2.2% last year to 1.2 to 2.4% this year.

The projected ten-year peak demand growth rate in Canada is 1.3% (Figure 2), equal to that experienced in Canada over the last ten years. Energy growth in Canada is projected to be 1.4%, slightly above the growth rate experienced over the last ten years. Forecast uncertainty is shown by the bandwidths around the base forecasts in Figure 2.

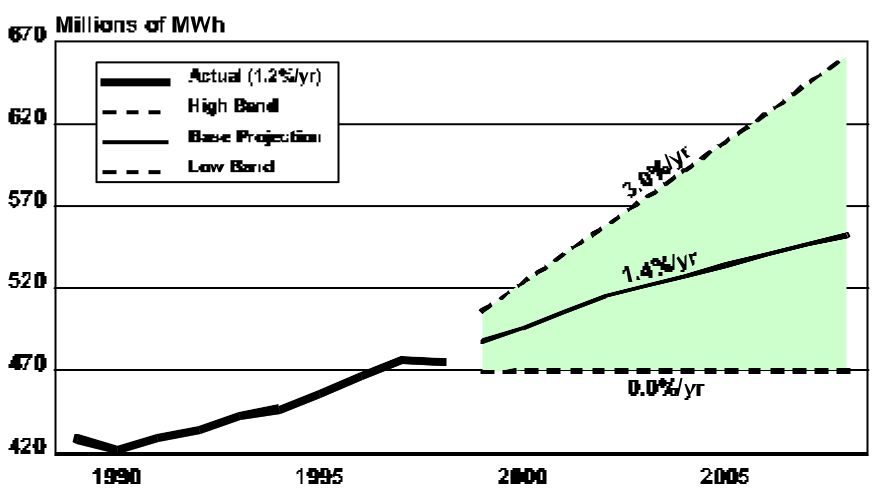
As in the United States, uncertainty in the demand forecast has increased the range of the LFWG forecast bandwidths from 0.2 to 2.7% last year to 0.0 to 2.8% this year. Similar increases in Canada's energy growth rate uncertainty are reflected in the increased bandwidth range from 0.1 to 2.8% last year to 0.0 to 3.0% this year.

Figure 2

Canada Peak Demand
1999-2008 Projection



Canada Net Energy for Load
1999-2008 Projection

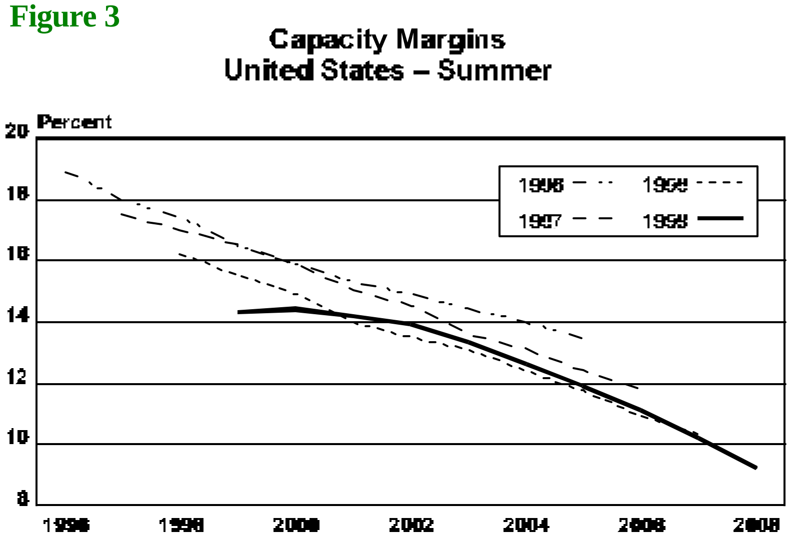


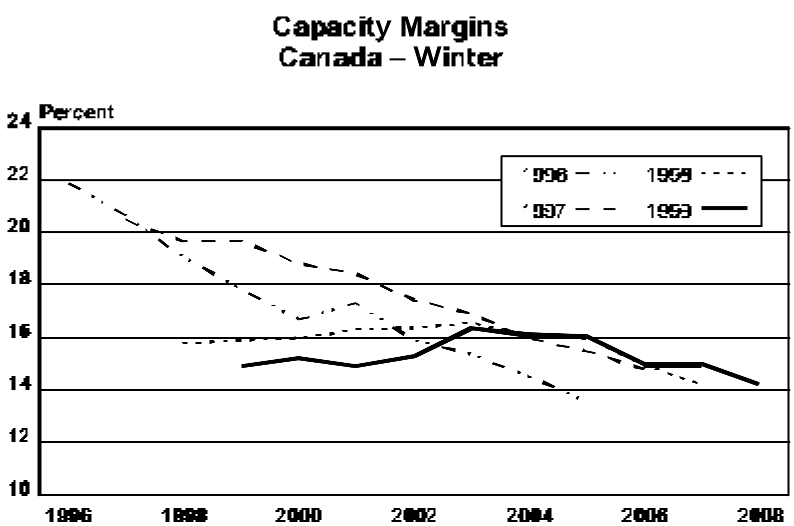
Resource Adequacy Assessment

Capacity adequacy in North America over the next ten years will be highly dependent upon the construction of new generation resources and innovative use of controllable demand-side resources. Most of the new generation is expected to be constructed by the competitive resource industry. The merchant generators have announced plans for over 100,000 MW1 of new capacity, and more capacity additions are being announced daily. However, most of that merchant capacity was not included in the capacity margins reported to NERC. The announced merchant generation will serve to increase the reported margins.

Actual demand and energy growth rates experienced in the United States over the last ten years have been significantly higher than the current projections. Actual growth rates have been closer to the rate calculated as the high band for both demand and energy.

Figure 3





The evolution to a market-based electricity supply will present significant challenges to accurately forecast demand. Given the critical nature of the demand forecasts in ensuring continued resource adequacy, the method of developing and reporting demand forecasts must undergo major revisions now to keep pace. Demand forecast data collection is addressed further in the Reliability Issues section of this report.

Capacity margins in the United States continue to decline from projections of the last few years (Figure 3), falling below 10% by the end of the assessment period. The sharp drop in capacity margin in 1999 from the projections of 1998 is disconcerting. This is the third year in a row that the initial forecast year capacity margin has dropped significantly. This trend is indicative of generation additions lagging the current demand growth.

Significant additional capacity has been announced to be brought into service in the next 18 to 24 months. If demand projections hold for summer 2000, the margin is expected to remain fairly flat. However, if demand grows at the historic 2.6% rate, the capacity margins in the United States would drop by about four percentage points.

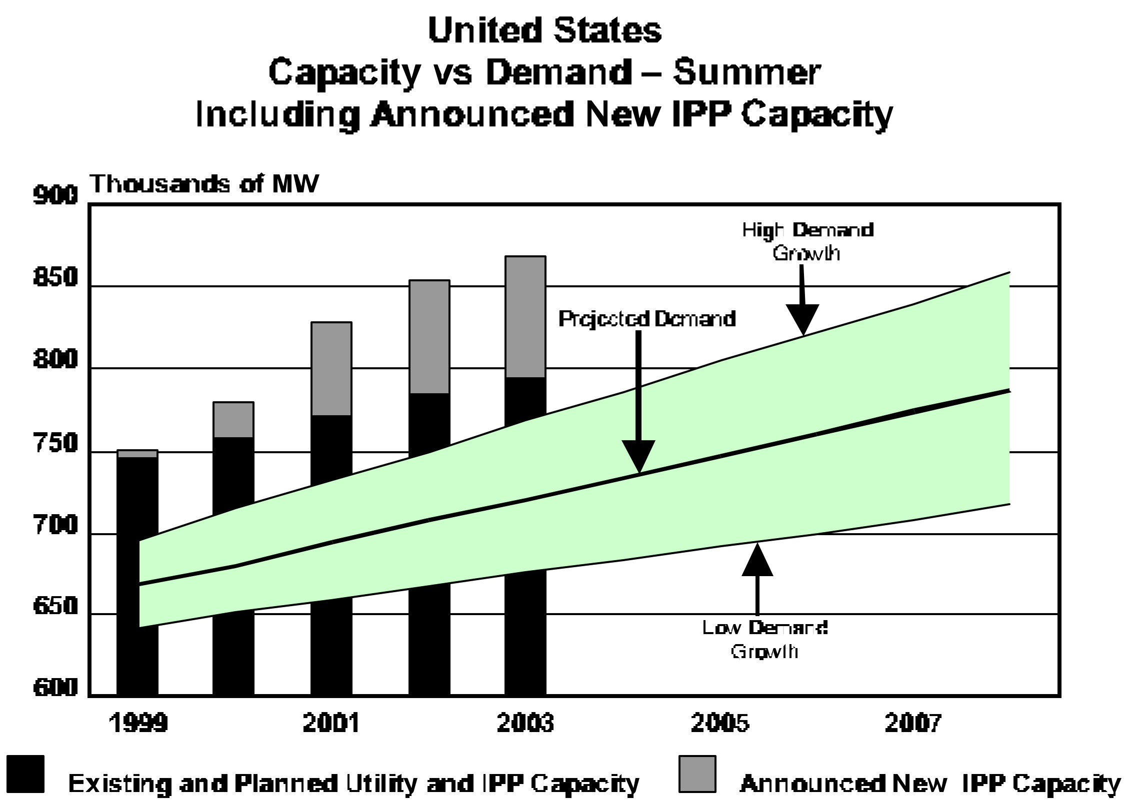
1 As of September 1, 1999. Substantial amounts of new merchant capacity announcements have been made since that time.

The profile of the projected Canadian capacity margins (Figure 3) has also dropped by one percentage point for 1999. This is not as dramatic a change as the one caused by the 1998 “lay-up” of 3,400 MW of nuclear capacity in Ontario. No specific plans have been announced yet for returning those generators to service.

A number of Regions and subregions have discontinued reporting even uncommitted resource additions needed to satisfy Regional criteria, contributing to the significant decline in the reported margins in the latter years of the ten-year review period. Also, substantial amounts of merchant generation plans are not captured by the traditional NERC data collection system, which only includes merchant generation capacity that is under contract.

Merchant or independent generation is expected to play a major role in the future power supply of North America, as shown in Figure 4. Additional information on announced merchant generation capacity additions, compiled by the Electric Power Supply Association (EPSA), was used in this report to gauge the level of reliance on new merchant capacity. EPSA is tracking plans for over 75,400 MW[2] of merchant generation additions that have been announced for construction in the United States by the end of 2003, with an additional 25,000 MW without planned in-service dates. About 56,700 MW of new merchant capacity is planned before the end of 2001. About 39,200 MW of the total is in the Eastern Interconnection, with about 10,200 MW in the ERCOT Interconnection and about 7,300 MW in the Western Interconnection. Although not all of that capacity is assured of being constructed, it is obvious that reliability will be highly dependent on those capacity additions. It is also important to note that all or part of the 10,600 MW of planned capacity reported by the Regions may be included in the announced merchant capacity being tracked by EPSA.

Figure 4

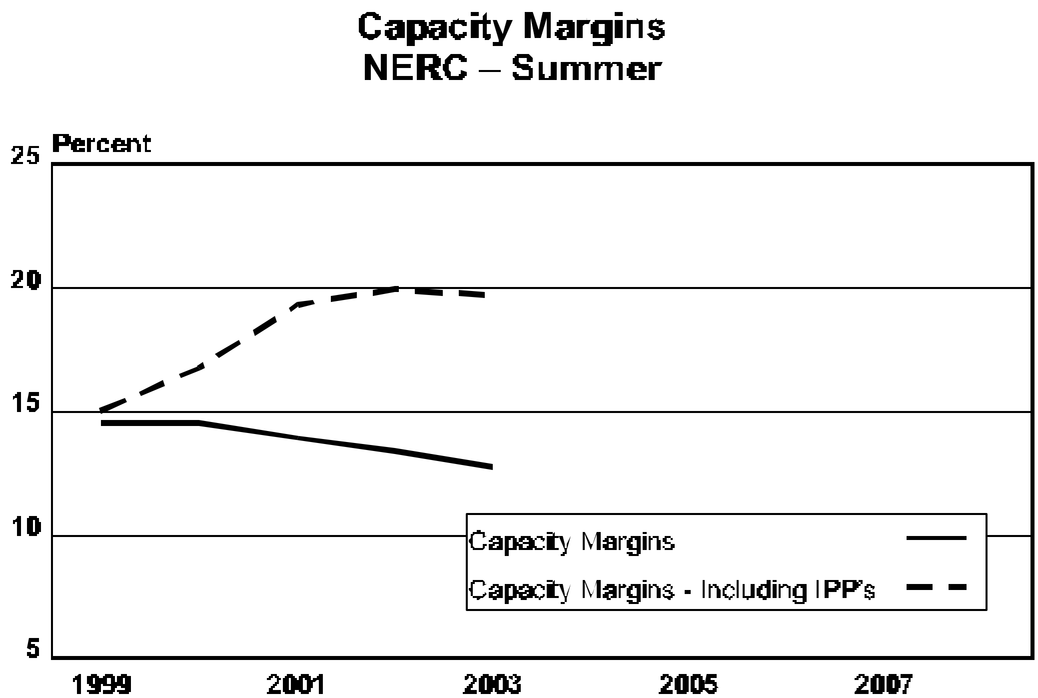


2 All EPSA generation values are as of September 1, 1999, to be more consistent with the 1999 demand forecasts produced in April 1999. Substantial amounts of new merchant capacity announcements have been made since that time.

NERC is working with EPSA and the Energy Information Administration of the U.S. Department of Energy to improve its data collection methods to more accurately capture merchant plant generation additions for inclusion in its reliability analyses.

The substantial impact of the announced merchant generation on the total NERC capacity margin is shown in Figure 5. The capacity margin for the United States could be significantly improved from 14.2 to 19.9% by the summer of 2001 if all of the announced generation additions are constructed.

Figure 5



To be effective in supporting the power supply reliability of North America, all planned generation additions must also be constructed on time to serve demand growth. Capacity margins have not been as critically low since the early 1970s, making generation in-service dates more important. If the announced merchant generation additions come on line as projected, capacity margins will be good. However, if the announced capacity is delayed in construction, the results may be capacity shortfalls in some areas. It should be noted that substantial amounts of new merchant capacity have been announced above that shown in Figure 5 and more announcements are being made almost every day.

NERC will continue to monitor and report trends of demand growth, generation additions, and the resultant capacity margins to provide reliability-based information to supplement the market price signals that drive market participants to plan and construct adequate capacity.

Table 1

Region	Projected Total Internal Demand (MW)	Projected Net Internal Demand (MW)	Planned Net Capacity Resources (MW)	Capacity Margins[1] (% of Net Capacity Resources)	Adjusted Net Capacity Resources[2] (MW)	Adj. Capacity Margins[3] (% of Adj. Net Capacity Resources)
1999 Summer						
ECAR	95,675	92,359	105,545	12.5	105,945	12.9
ERCOT	53,330	50,254	59,788	15.9	60,788	17.6
FRCC[4]	37,327	34,562	39,708	13.0	39,708	13.0
MAAC	49,807	47,626	55,511	14.2	55,761	14.7
MAIN	47,875	45,570	52,722	13.6	52,972	14.0
MAPP – U.S.	31,991	29,766	34,773	14.4	34,773	14.4
MAPP – Canada	5,449	5,217	7,992	34.7	7,992	34.7
NPCC – U.S.	51,841	51,760	60,439	14.4	61,233	15.7
NPCC – Canada	43,465	40,570	65,298	37.9	65,298	37.9
SERC	147,223	138,146	158,360	12.8	159,485	13.5
SPP	38,180	36,402	42,554	14.5	42,554	14.5
WSCC – U.S.	115,901	111,641	135,270	17.5	136,230	18.2
WSCC – Canada	14,924	14,562	20,367	28.5	20,367	28.5
WSCC – Mexico	1,447	1,447	1,778	18.6	1,778	18.6
United States	669,150	638,086	744,670	14.3	749,449	15.0
Canada	63,838	60,349	93,657	35.6	93,657	35.6
Mexico	1,447	1,447	1,778	18.6	1,778	18.6
NERC Total	734,435	699,882	840,105	16.7	844,884	17.3
2008 Summer						
ECAR	111,562	108,148	112,996	4.3	118,820	9.4
ERCOT	65,210	62,254	67,485	7.8	67,485	7.8
FRCC[4]	44,208	41,408	48,850	15.2	48,850	15.2
MAAC	57,381	55,141	57,907	4.8	63,122	13.8
MAIN	54,606	52,124	61,116	14.7	65,452	21.8
MAPP – U.S.	37,146	34,252	34,608	1.0	35,570	3.8
MAPP – Canada	5,839	5,698	8,152	30.1	8,152	30.1
NPCC – U.S.	58,685	58,577	62,718	6.6	84,831	41.9
NPCC – Canada	49,228	47,202	74,022	36.2	74,022	36.2
SERC	179,607	170,644	192,908	11.5	196,913	13.6
SPP	45,643	43,348	48,837	11.2	48,837	11.2
WSCC – U.S.	133,110	128,653	142,407	9.7	153,710	17.6
WSCC – Canada	17,286	17,286	22,170	22.0	22,170	22.0
WSCC – Mexico	2,555	2,555	3,228	20.8	3,228	20.8
United States	787,158	754,549	829,832	9.1	883,590	15.6
Canada	72,353	70,186	104,344	32.7	104,344	32.7
Mexico	2,555	2,555	3,228	20.8	3,228	20.8
NERC Total	862,066	827,290	937,404	11.7	991,162	17.5

1. $\frac{\{[\text{Planned Net Capacity Resources}] \text{ less } [\text{Net Internal Demand}]\}}{[\text{Planned Net Capacity Resources}]} \times 100$
2. Capacity resources adjusted for announced new merchant plant capacity.
3. Margins adjusted for announced new merchant plant capacity.
4. FRCC uses Reserve Margin, not Capacity Margin, as one of its guidelines in assessing adequacy. The FRCC Load and Resource data was finalized on July 1, 1999, and is not reflected in this analysis.

Table 1 (continued)

Region	Projected Total Internal Demand (MW)	Projected Net Internal Demand (MW)	Planned Net Capacity Resources (MW)	Capacity Margins[1] (% of Net Capacity Resources)	Adjusted Net Capacity Resources[2] (MW)	Adj. Capacity Margins[3] (% of Adj. Net Capacity Resources)
1999/2000 Winter						
ECAR	86,020	82,974	105,521	21.4	105,921	21.7
ERCOT	42,574	39,630	60,071	34.0	61,071	35.7
FRCC[4]	40,165	36,153	41,769	13.4	41,769	13.4
MAAC	43,009	41,859	57,956	27.8	58,206	28.2
MAIN	38,170	36,205	52,308	30.8	52,558	31.3
MAPP – U.S.	26,781	25,609	33,961	24.6	33,961	24.6
MAPP – Canada	6,626	6,387	7,906	19.2	7,906	19.2
NPCC – U.S.	44,292	44,160	60,967	27.6	61,761	28.9
NPCC – Canada	59,304	57,081	67,435	15.4	67,435	15.4
SERC	130,738	123,533	158,892	22.3	160,017	23.0
SPP	27,986	27,180	42,239	35.7	42,239	35.7
WSCC – U.S.	103,087	101,748	136,635	25.5	137,595	26.2
WSCC – Canada	18,334	17,972	20,171	10.9	20,171	10.9
WSCC – Mexico	1,048	1,048	1,608	34.8	1,608	34.8
United States	582,822	559,051	750,319	25.5	755,098	26.1
Canada	84,264	81,440	95,512	14.7	95,512	14.7
Mexico	1,048	1,048	1,608	34.8	1,608	34.8
NERC Total	668,134	641,539	847,439	24.3	852,218	24.9
2008/2009 Winter						
ECAR	99,567	96,477	112,265	14.1	118,089	19.3
ERCOT	53,707	50,757	67,476	24.8	67,476	24.8
FRCC[4]	48,566	44,411	51,643	14.0	51,643	14.0
MAAC	48,981	47,823	60,735	21.3	65,950	29.8
MAIN	43,385	41,591	60,461	31.2	64,797	38.4
MAPP – U.S.	30,304	28,998	34,008	14.7	34,970	17.6
MAPP – Canada	7,154	7,006	8,069	13.2	8,069	13.2
NPCC – U.S.	50,221	50,087	64,162	21.9	86,275	56.4
NPCC – Canada	66,227	64,007	75,231	14.9	75,231	14.9
SERC	158,625	151,104	196,468	23.1	200,473	25.1
SPP	33,657	32,579	48,291	32.5	48,291	32.5
WSCC – U.S.	117,412	116,000	143,877	19.4	155,180	27.2
WSCC – Canada	21,259	21,259	22,066	3.7	22,066	3.7
WSCC – Mexico	1,777	1,777	3,286	45.9	3,286	45.9
United States	684,425	659,827	839,386	21.4	893,144	27.8
Canada	94,640	92,272	105,366	12.4	105,366	12.4
Mexico	1,777	1,777	3,286	45.9	3,286	45.9
NERC Total	780,842	753,876	948,038	20.5	1,001,796	26.2

1. $$\frac{\{[\text{Planned Net Capacity Resources}] \text{ less } [\text{Net Internal Demand}]\}}{[\text{Planned Net Capacity Resources}]} \times 100$$
2. Capacity resources adjusted for announced new merchant plant capacity.
3. Margins adjusted for announced new merchant plant capacity.
4. FRCC uses Reserve Margin, not Capacity Margin, as one of its guidelines in assessing adequacy. The FRCC Load and Resource data was finalized on July 1, 1999, and is not reflected in this analysis.

Interconnection Analysis

The Interconnection Analysis examines the resource adequacy of the three Interconnections in North America. Trends are examined in projections of demand, capacity resources, the growing reliance on wholesale purchases from others, and generating capacity not yet under construction.

The Interconnection margins and resources in this section are not simple additions of the constituent Regions in each Interconnection. Interconnection capacity margin and net interconnection capacity resources are terms specifically defined for this Interconnection analysis. These terms are used to quantify the generation within an Interconnection and the ability of the Interconnection to import resources from neighboring Interconnections. Net purchases and sales are not included in this calculation because all purchases and sales are limited to the resources within the Interconnection or by importing over the HVDC ties with the other Interconnections. A new 200 MW HVDC tie is planned to be in service in 2004 between SPP and WSCC. No other plans to increase the Interconnection tie capability were reported. The tie capability between ERCOT and the other Interconnections was assumed to be constant throughout the assessment period.

Demand diversity within an Interconnection may vary greatly due to demographics and the size and nature of the demand within the Interconnection. However, the impact of demand diversity on capacity margins can be counteracted and sometimes outweighed by forced outages of generation caused by equipment failures. It should be noted that the 1996–1998 average equivalent forced outage rate of generation during the summer in North America was 9.3% based on all units reporting to the NERC Generating Availability Data System (GADS). To adequately address this interaction, probabilistic analysis would be required. Therefore, both demand diversity and generation availability were excluded from the calculation of the Interconnection capacity margins.

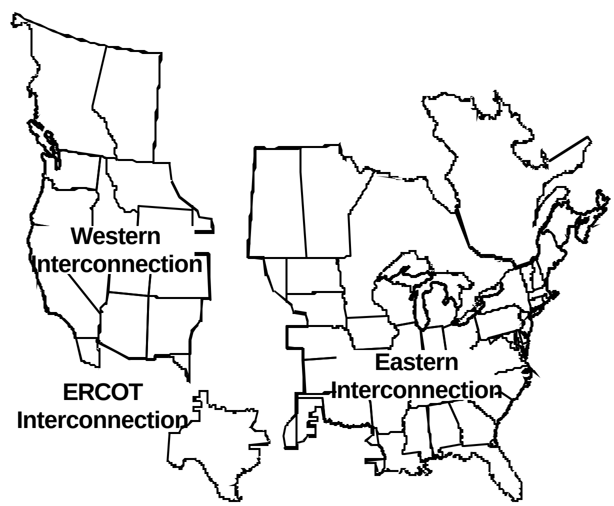
The Interconnections

The electric systems in the United States and Canada comprise three Interconnections:

Eastern Interconnection — the largest Interconnection covers an area from Québec and the Maritimes to Florida and the Gulf Coast in the East and from Saskatchewan to eastern New Mexico in the West. It has HVDC connections to the Western and ERCOT Interconnections.

Western Interconnection — the second largest Interconnection extends from Alberta and British Columbia in the North to Baja California Norté, Mexico, and Arizona and New Mexico in the South. It has several HVDC connections to the Eastern Interconnection.

ERCOT Interconnection — includes most of the electric systems in Texas with two HVDC connections to the Eastern Interconnection.



Interconnection Table Legend

The following legend is applicable to all of the Interconnection tables listed in the section.

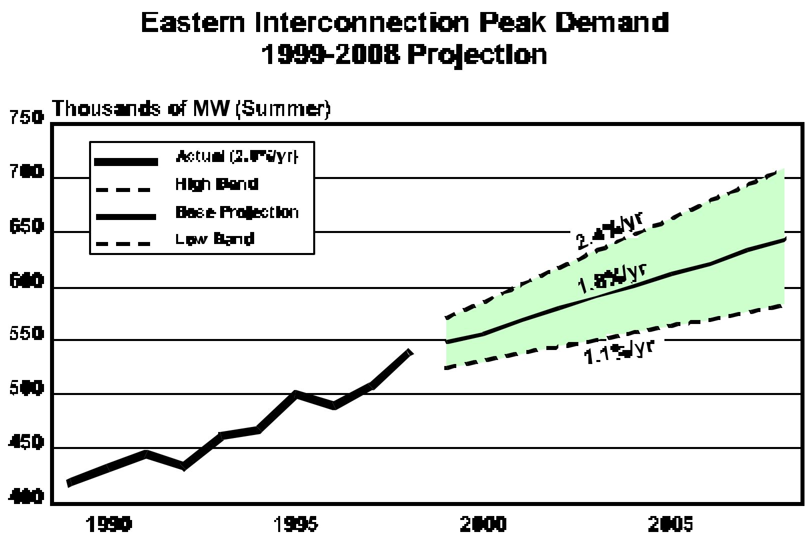
Projected Interconnection Internal Demand	Sum of Internal Demand plus Standby Demand (monthly coincident) for the Interconnection
Interconnection Interruptible Demand & DCLM	Sum of Interruptible Demand and Direct Control Load Management (DCLM) for the Interconnection
Projected Interconnection Net Internal Demand	Projected Interconnection Internal Demand less Interconnection Interruptible Demand and DCLM
Projected Interconnection Generating Capacity	Sum of Projected Utility Generating Capacity plus Projected Merchant Generation Capacity (Purchased) for the Interconnection
Interconnection Tie Capability	Import Capability of the Interconnection's HVDC ties to other Interconnections
Net Interconnection Capacity Resources	Projected Interconnection Generation plus Interconnection Tie Capability
Interconnection Margin	Net Interconnection Capacity Resources less Projected Interconnection Net Internal Demand
Interconnection Capacity Margin (%)	Interconnection Margin divided by Net Interconnection Capacity Resources, expressed as a percentage
Net Interconnection Capacity Resources Less Capacity Not Under Construction	Existing Capacity, less Planned Capacity Retirements, plus Planned Capacity Reactivations, plus Capacity Under Construction, plus Interconnection Tie Capability
Projected Capacity Additions	Projected Capacity Additions (cumulative, not under construction) for the Interconnection
Projected Capacity Additions as % of Projected Internal Demand	Projected Capacity Additions as a percentage of Projected Internal Demand
Projected Capacity Additions as % of Capacity Margin	Projected Capacity Additions as a percentage of MW Margin
Announced New Merchant Capacity	Announced New Merchant generating capacity (cumulative)
Net Interconnection Capacity Resources Plus Merchant Capacity	Projected Interconnection Generation plus Announced New Merchant Capacity plus Interconnection Tie Capability
Interconnection Margin Adjusted for Announced Merchant Capacity	Net Interconnection Capacity Resources plus Announced New Merchant Capacity less Projected Interconnection Net Internal Demand
Interconnection Capacity Margin Adjusted for Announced Merchant Capacity (%)	Interconnection Margin plus Adjusted for Announced Merchant Capacity divided by Net Interconnection Capacity Resources, expressed as a percentage
Projected Interconnection Net Purchases	Projected Interconnection Purchases less Projected Interconnection Sales among the Regions in the Interconnection and from the other Interconnections
Projected Interconnection Net Purchases as % of Projected Internal Demand	Projected Net Purchases divided by Projected Interconnection Net Internal Demand, expressed as a percentage
Projected Interconnection Net Purchases as % of Interconnection Tie Capability	Projected Net Purchases divided by Projected Interconnection Net Internal Demand, expressed as a percentage

Eastern Interconnection

The Eastern Interconnection is in critical need of additional generating capacity within the next two to three years. Most of the needed additional generation is expected to be constructed by the growing merchant generation sector of the industry.

Demand in the Eastern Interconnection is projected to grow at 1.8% per year, which is well below the 2.8% growth experienced over the last ten years (Figure 6). Uncertainty in the demand forecast has slightly increased the range of the bandwidths from 1.2 to 2.3% last year to 1.2 to 2.4% this year. Demand increases experienced during the summer of 1999 continue to point toward a higher growth trend.

Figure 6



Reported capacity margins for the Eastern Interconnection are above those projected last year for the first few years (Figure 7). Margins continue to decline in the latter years of the analysis, indicating a growing need for new resources.

Figure 7

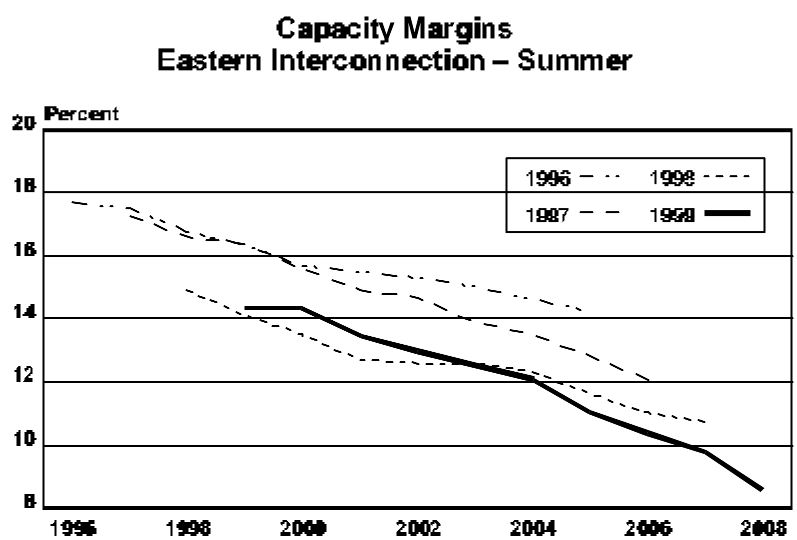


Figure 8 shows that the reported existing and planned generation additions in the Eastern Interconnection can only support the upper demand bandwidth projections through the summer of 2004. There is time for additional generation to be constructed by that time. However, the situation gets much worse when you consider the average forced outage rates for generation in the summer.

Figure 8

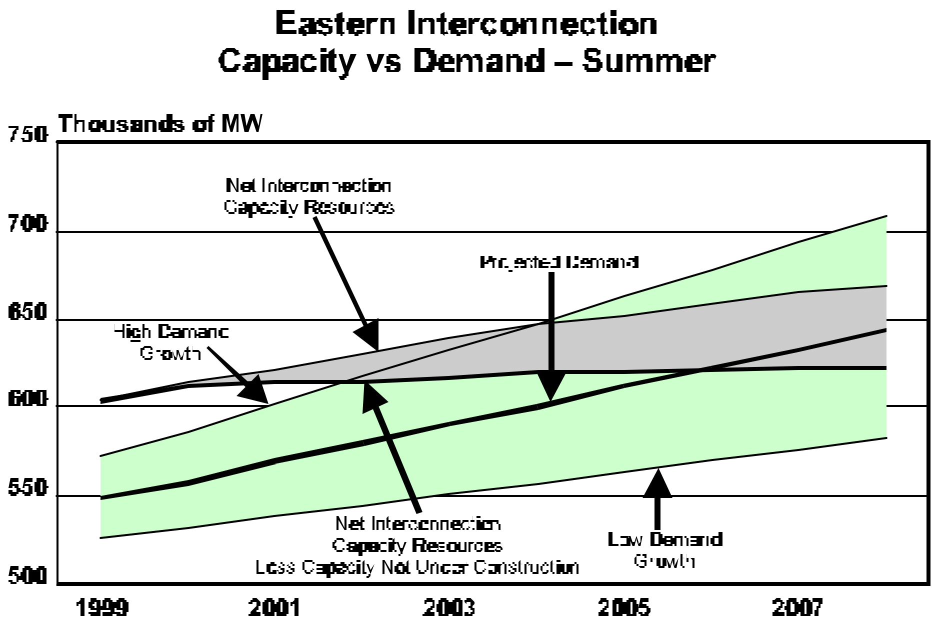


Figure 9 shows the relationship between capacity, adjusted for the average summer generation forced outages of 9.3%[3], and the projected demand of the Eastern Interconnection. If demand were to grow as projected, the outage-adjusted existing and under construction generation reported to NERC would be less than the net summer peak demand (with all direct control load management cut and interruptible demands curtailed) by the summer of 2001. The Interconnection's ability to serve demand would be completely reliant on demand diversity within the Interconnection and its ability to import resources through its ties. Although the benefits of demand diversity could potentially be great within the Eastern Interconnection, it can often be surprisingly small when a wide-area heat wave occurs, as experienced in the summer of 1999. Also, the ability to take advantage of the diversity within the Interconnection is subject to transmission limitations. For instance, existing transmission limitations into and out of New England and on other intervening transmission systems make it impossible to take full advantage of demand diversity between New England and Florida. Forced outages of generation during the last few summers in MAIN and New England demonstrated the potential for deliverability problems of remote replacement capacity resources.

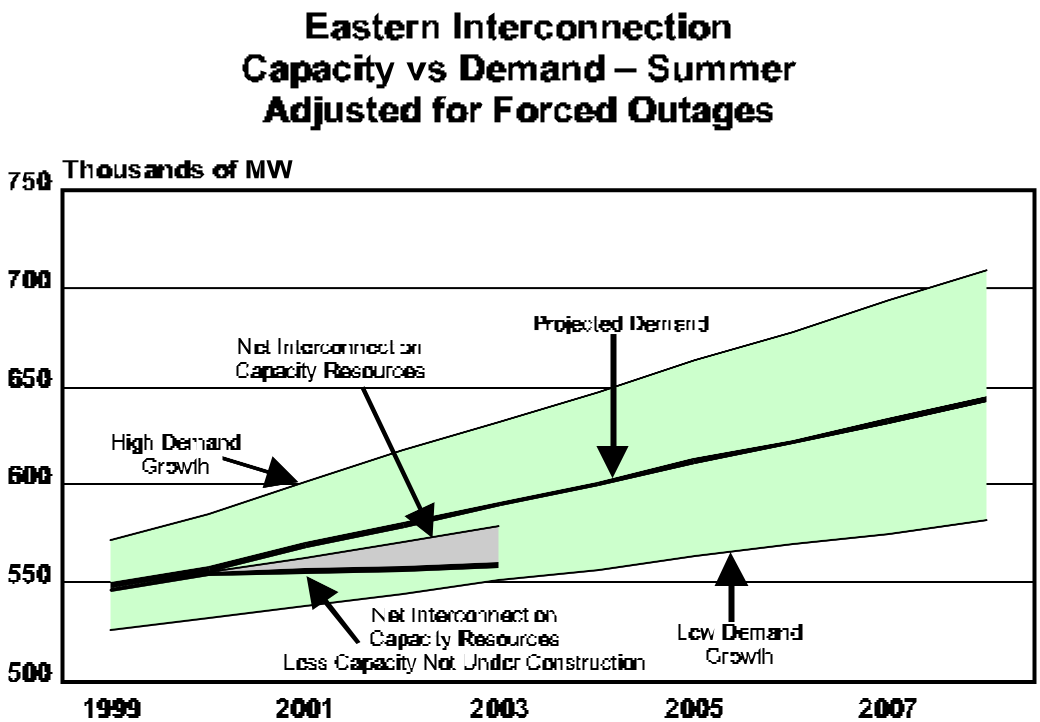
It is apparent that the Eastern Interconnection is in critical need of additional generating capacity within the next two to three years. However, Table 2 also shows that more than half of the Interconnection margin of the Eastern Interconnection will consist of capacity not yet under construction by the summer of 2004. Over 80% of the entire Interconnection capacity margin planned for 2008 is not yet under construction.

3 Based on NERC Generating Availability Data System (GADS) North American average for third quarter, 1996–1998.

As reported to NERC, the generation resources (excluding merchant generator capacity) and capacity purchases planned for meeting the future demand of the Eastern Interconnection reflect a number of important trends:

- Reported capacity purchases show a growing trend of reliance on purchases from undisclosed sources (the open market) to serve firm customer demand. Such purchases may indicate an over a reliance on the capacity margin and demand diversity within the Interconnection, and the tie capacity of the Interconnection. Table 2 shows that the aggregate net purchase for the Eastern Interconnection for 2000 is over 300% of the 1,560 MW HVDC tie capability of the Interconnection.
- A number of "as-yet" uncommitted generator capacity additions are reported as planned within the Interconnection. Some of these generators are proxies for a recognized need for additional capacity, while others are actual planned unit additions.

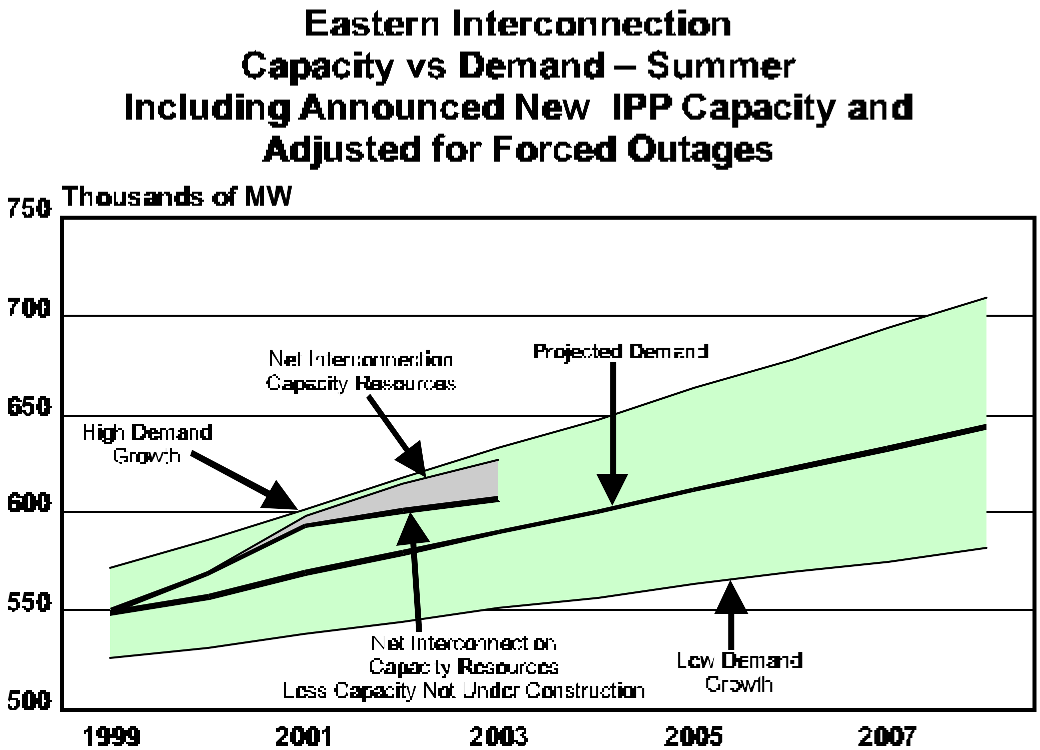
Figure 9



Merchant generation additions are expected to be an important factor in the Eastern Interconnection. The reported projected summer capacity margin for the Interconnection in 2000 is 14.3%. However, over 10,000 MW of additional merchant generation capacity (above what is captured in NERC's data collection) has been announced[4]. If the additional generation is included, the Interconnection capacity margin improves to about 16%. Figure 10 shows the enhanced capacity situation of the Eastern Interconnection with the announced merchant capacity, even when adjusted for the influence of generation forced outages.

Within the Eastern Interconnection, there are about 35,300 MW of planned generation additions that have been reported to NERC to be constructed before the summer of 2003. EPSA is tracking another 48,300 MW[4] of additional announced merchant plant capacity additions in the Eastern Interconnection for construction by that time. Another 15,000 MW have been announced, but have no scheduled in-service date. It is expected that not all of the planned and announced generation will be ultimately built, and that there may be some duplication of resources in the future generation data reporting. NERC is working with EPSA and the EIA to improve generation data collection procedures for use in its reliability analyses.

Figure 10



4 All EPSA generation values are as of September 1, 1999, to be more consistent with the 1999 demand forecasts produced in April 1999. Substantial amounts of new merchant capacity announcements have been made since that time.

Table 2 — Eastern Interconnection – Summer

	1999	2000	2001	2002	2003
Projected Interconnection Internal Demand	548,833	557,118	569,372	579,939	590,568
Interconnection Interruptible Demand & DCLM	26,855	26,116	26,809	26,670	26,804
Projected Interconnection Net Internal Demand	521,978	531,002	542,563	553,269	563,764
Projected Interconnection Generating Capacity	602,491	612,942	619,816	628,907	637,766
Interconnection Tie Capability	1,560	1,560	1,560	1,560	1,560
Net Interconnection Capacity Resources	604,051	614,502	621,376	630,467	639,326
Interconnection Margin	82,073	83,500	78,813	77,198	75,562
Interconnection Capacity Margin (%)	13.6	13.6	12.7	12.2	11.8
Net Interconnection Capacity Resources Less Capacity Not Under Construction	603,836	612,650	614,459	614,607	617,210
Projected Capacity Additions	215	1,852	6,917	15,860	22,116
Projected Capacity Additions as % of Projected Internal Demand	0.0	0.3	1.3	2.9	3.9
Projected Capacity Additions as % of Capacity Margin	0.3	2.2	8.8	20.5	29.3
Announced New Merchant Capacity	2,819	14,626	39,201	47,293	51,620
Net Interconnection Capacity Resources Plus Merchant Capacity	606,870	629,128	660,577	677,760	690,946
Interconnection Margin Adjusted for Announced Merchant Capacity	84,892	98,126	118,014	124,491	127,182
Interconnection Capacity Margin Adjusted for Announced Merchant Capacity (%)	14.0	15.6	17.9	18.4	18.4
Projected Interconnection Net Purchases	20,605	20,858	24,447	26,499	28,288
Projected Interconnection Net Purchases as % of Projected Internal Demand	3.8	3.7	4.3	4.6	4.8
Projected Interconnection Net Purchases as % of Interconnection Tie Capability	298.6	302.3	354.3	384.0	410.0

Table 2 — Eastern Interconnection – Summer (continued)

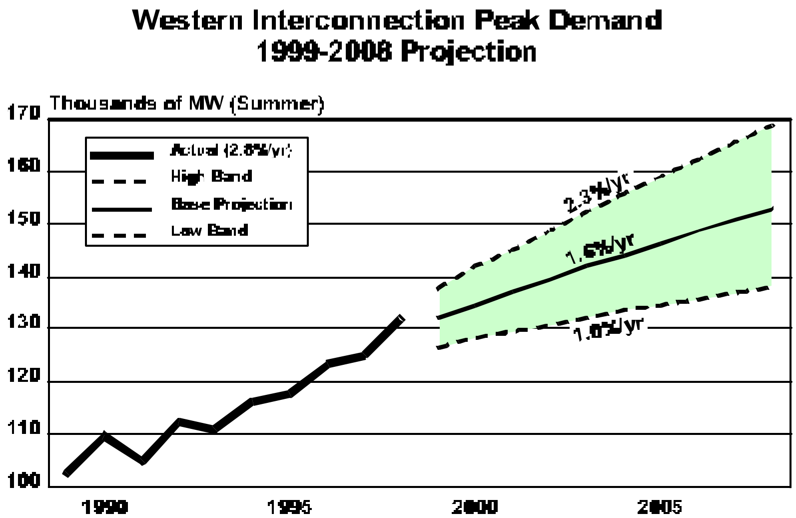
	2004	2005	2006	2007	2008
Projected Interconnection Internal Demand	600,479	611,862	622,339	632,977	643,905
Interconnection Interruptible Demand & DCLM	27,028	27,242	27,165	27,446	27,363
Projected Interconnection Net Internal Demand	573,451	584,620	595,174	605,531	616,542
Projected Interconnection Generating Capacity	645,200	650,462	657,004	663,939	667,224
Interconnection Tie Capability	1,560	1,760	1,760	1,760	1,760
Net Interconnection Capacity Resources	652,100	657,562	664,104	671,039	674,324
Interconnection Margin	78,649	72,942	68,930	65,508	57,782
Interconnection Capacity Margin (%)	12.1	11.1	10.4	9.8	8.6
Net Interconnection Capacity Resources Less Capacity Not Under Construction	620,039	620,492	621,656	622,934	622,355
Projected Capacity Additions	26,721	31,730	37,108	42,765	46,629
Projected Capacity Additions as % of Projected Internal Demand	4.7	5.4	6.2	7.1	7.6
Projected Capacity Additions as % of Capacity Margin	36.4	46.9	58.4	71.1	88.9
Announced New Merchant Capacity	51,620	51,620	51,620	51,620	51,620
Net Interconnection Capacity Resources Plus Merchant Capacity	698,380	703,842	710,384	717,319	720,604
Interconnection Margin Adjusted for Announced Merchant Capacity	124,929	119,222	115,210	111,788	104,062
Interconnection Capacity Margin Adjusted for Announced Merchant Capacity (%)	17.9	16.9	16.2	15.6	14.4
Projected Interconnection Net Purchases	28,035	28,997	30,303	29,607	30,735
Projected Interconnection Net Purchases as % of Projected Internal Demand	4.7	4.7	4.9	4.7	4.8
Projected Interconnection Net Purchases as % of Interconnection Tie Capability	406.3	408.4	426.8	417.0	432.9

It is clear that additional generating capacity, above what has been reported, will be needed in the Eastern Interconnection to maintain adequate operating margins. Hopefully, many of the announced generation additions will be constructed on time to meet the continuing demand growth in the Interconnection. If not, significant amounts of new interruptible demand and direct control load management will be needed to offset the potential shortfalls.

Western Interconnection

Resource adequacy of the Western Interconnection will hinge largely on generation capacity additions made by the merchant generation developers. Announced merchant generation additions over the next five years are more than double the capacity additions reported to NERC by utilities in the Interconnection. Because of the nature of the Western Interconnection's bulk power system, with large demand centers separated by long lines, location of the generation additions will be key to its deliverability.

Figure 11



Demand in the Western Interconnection is projected to grow at 1.6% per year compared with the 2.8% average growth experienced in the West over the last ten years (Figure 11). That growth rate projection is significantly less than the 1.9% growth rate projected last year. The current year demand projections for 1999 also show about a 5% increase over last year's forecast.

The Western Interconnection capacity margin has a significant drop (Figure 12) for 1999 through 2002, mostly due to the jump in demand forecast for 1999. The margin then continues to show the declining trend over the assessment period, which is more consistent with margin projections made in recent years.

Figure 12

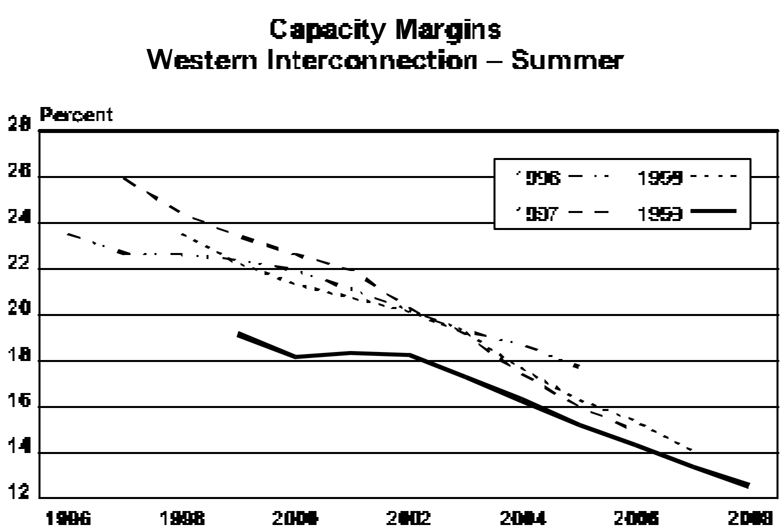


Figure 13 shows that the reported existing and planned generation additions in the Western Interconnection can support the upper demand bandwidth projections through 2008. Additional announced generation will also be constructed during that time.

Figure 13

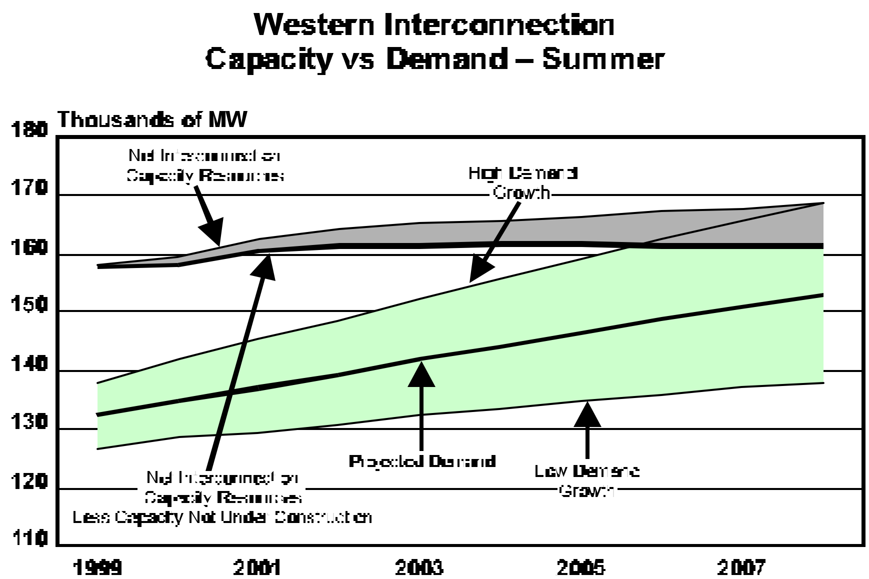
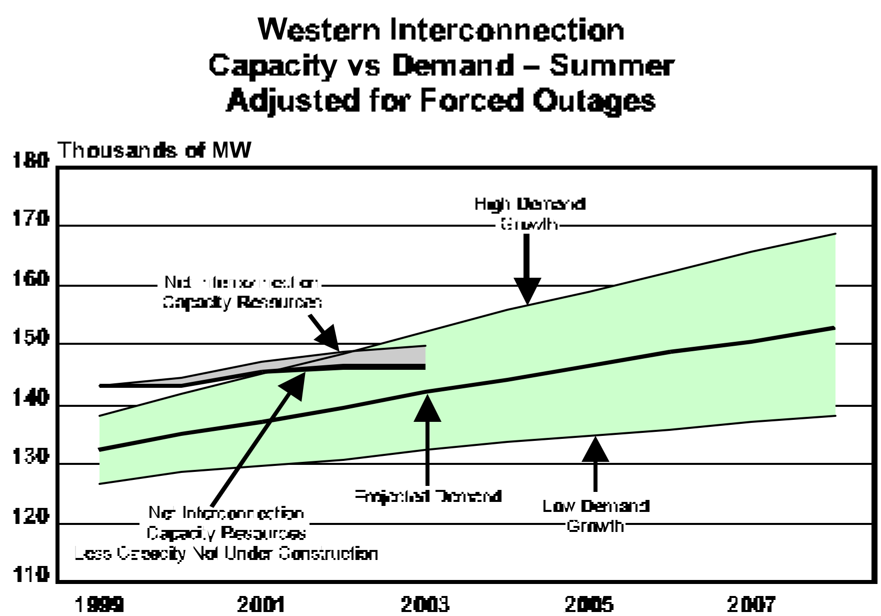


Figure 14 shows the relationship between the Western Interconnection capacity, adjusted for the average summer generation forced outages of 9.3%[5], and the projected demand. Under those conditions, the reported existing and planned resource can support the upper demand bandwidth of the Interconnection through 2002.

Figure 14

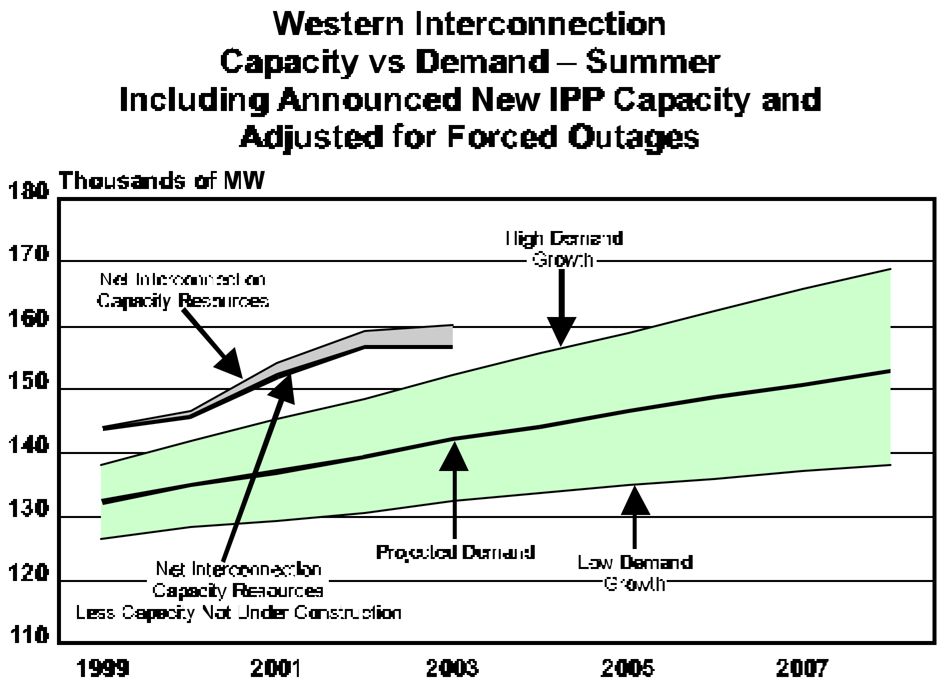


5 Based on NERC Generating Availability Data System (GADS) North American average for third quarter, 1996–1998.

The new merchant capacity can play a major role in improving the capacity margin of the Western Interconnection. As reported to NERC, the planned generation additions not under construction (excluding announced merchant generator capacity) in the Western Interconnection represent only 1.4% of the projected internal demand by 2003. However, EPSA is tracking about 11,300 MW[6] of additional merchant capacity additions in the Western Interconnection through the same period. That additional capacity could potentially raise the Interconnection's capacity margin from 16.7 to 22.1% in 2003 (Table 3).

Figure 15 shows that if the announced merchant generation additions are included in the adequacy analysis of the Western Interconnection, adjusted for the average summer generation forced outages, WSCC's ability to keep pace with demand is further improved.

Figure 15



6 All EPSA generation values are as of September 1, 1999, to be more consistent with the 1999 demand forecasts produced in April 1999. Substantial amounts of new merchant capacity announcements have been made since that time.

Table 3 — Western Interconnection – Summer

	1999	2000	2001	2002	2003
Projected Interconnection Internal Demand	132,272	134,743	137,178	139,439	141,990
Interconnection Interruptible Demand & DCLM	4,622	4,573	4,622	4,416	4,427
Projected Interconnection Net Internal Demand	127,650	130,170	132,556	135,023	137,563
Projected Interconnection Generating Capacity	156,822	157,986	161,225	162,986	164,126
Interconnection Tie Capability	1,080	1,080	1,080	1,080	1,080
Net Interconnection Capacity Resources	157,902	159,066	162,305	164,066	165,206
Interconnection Margin	30,252	28,896	29,749	29,043	27,643
Interconnection Capacity Margin (%)	19.2	18.2	18.3	17.7	16.7
Net Interconnection Capacity Resources Less Capacity Not Under Construction	157,664	157,902	160,412	161,258	161,241
Projected Capacity Additions	238	1,164	1,893	2,808	3,965
Projected Capacity Additions as % of Projected Internal Demand	0.2	0.9	1.4	2.1	2.9
Projected Capacity Additions as % of Capacity Margin	0.8	4.0	6.4	9.7	14.3
Announced New Merchant Capacity	960	2,540	7,333	11,303	11,303
Net Interconnection Capacity Resources Plus Merchant Capacity	158,862	161,606	169,638	175,369	176,509
Interconnection Margin Adjusted for Announced Merchant Capacity	31,212	31,436	37,082	40,346	38,946
Interconnection Capacity Margin Adjusted for Announced Merchant Capacity (%)	19.6	19.5	21.9	23.0	22.1
Projected Interconnection Net Purchases	593	343	396	423	293
Projected Interconnection Net Purchases as % of Projected Internal Demand	0.4	0.3	0.3	0.3	0.2
Projected Interconnection Net Purchases as % of Interconnection Tie Capability	54.9	31.8	36.7	39.2	27.1

Table 3 — Western Interconnection – Summer (continued)

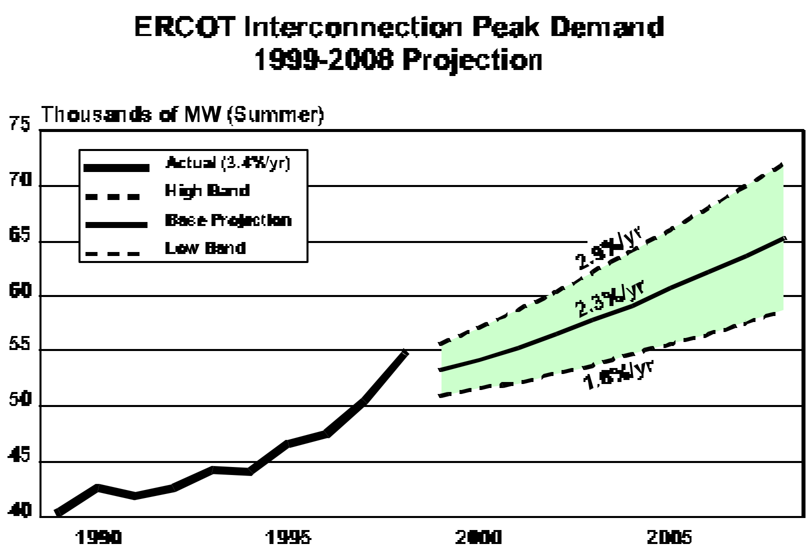
	2004	2005	2006	2007	2008
Projected Interconnection Internal Demand	144,052	146,498	148,671	150,807	152,951
Interconnection Interruptible Demand & DCLM	4,438	4,449	4,456	4,453	4,457
Projected Interconnection Net Internal Demand	139,614	142,049	144,215	146,354	148,494
Projected Interconnection Generating Capacity	164,548	165,228	166,174	166,734	167,562
Interconnection Tie Capability	1,080	1,280	1,280	1,280	1,280
Net Interconnection Capacity Resources	165,628	166,508	167,454	168,014	168,842
Interconnection Margin	26,014	24,459	23,239	21,660	20,348
Interconnection Capacity Margin (%)	15.7	14.7	13.9	12.9	12.1
Net Interconnection Capacity Resources Less Capacity Not Under Construction	161,453	161,658	161,469	161,426	161,451
Projected Capacity Additions	4,175	4,850	5,985	6,588	7,391
Projected Capacity Additions as % of Projected Internal Demand	3.0	3.4	4.2	4.5	5.0
Projected Capacity Additions as % of Capacity Margin	16.1	19.8	25.8	30.4	36.3
Announced New Merchant Capacity	11,303	11,303	11,303	11,303	11,303
Net Interconnection Capacity Resources Plus Merchant Capacity	176,931	177,811	178,757	179,317	180,145
Interconnection Margin Adjusted for Announced Merchant Capacity	37,317	35,762	34,542	32,963	31,651
Interconnection Capacity Margin Adjusted for Announced Merchant Capacity (%)	21.1	20.1	19.3	18.4	17.6
Projected Interconnection Net Purchases	293	293	243	243	243
Projected Interconnection Net Purchases as % of Projected Internal Demand	0.2	0.2	0.2	0.2	0.2
Projected Interconnection Net Purchases as % of Interconnection Tie Capability	27.1	22.9	19.0	19.0	19.0

ERCOT Interconnection

ERCOT appears to be in the best condition of the three Interconnections to reliably serve customer demand over the forecast period. Despite high demand growth experienced over the past few years due to a robust economy and higher than expected temperatures, planned and announced capacity additions are expected to provide adequate capacity resources.

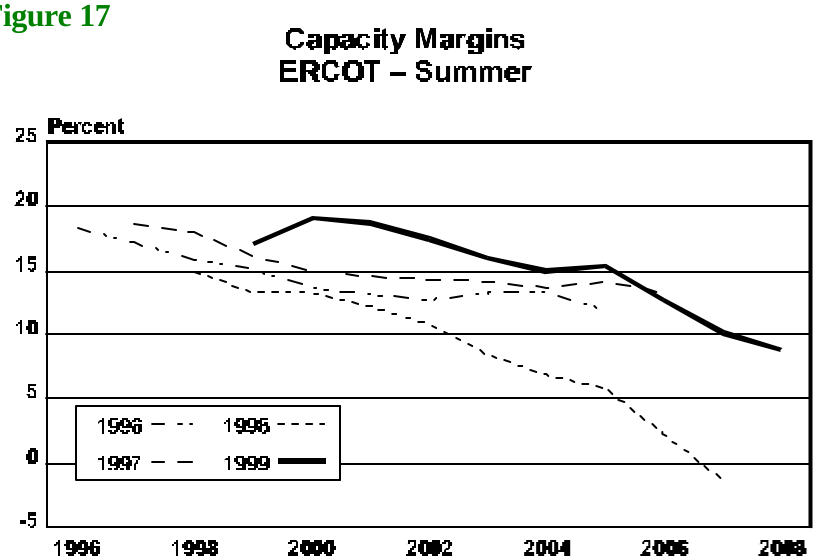
Demand in the ERCOT Interconnection is projected to grow at 2.3% per year, compared with the 3.4% average growth experienced in ERCOT over the last ten years (Figure 16). The high and low bandwidths assume normal long-term weather patterns. Actual peak load growth in ERCOT has been exceptionally high during the past several years primarily due to a robust economy and population growth, coupled with a record-breaking heat wave that swept Texas during the summer of 1998. However, the demand forecast for ERCOT of 2.3% is very conservative and assumes normal temperatures and some tapering off of the economy and population growth in the state.

Figure 16



The reported ERCOT Interconnection's capacity margin (Figure 17), absent new announced merchant capacity, is higher than that of the other two Interconnections. This allows its generating capacity to support significantly higher-than-projected peak demands. ERCOT also has significant demand-side management programs equal to almost 6% of the projected internal demand. The extreme weather conditions of the 1997 and 1998 summers highlight that demand spikes of 5% above forecast can and do occur in the Interconnection. ERCOT's robust capacity margin and demand-side programs enabled the Region to reliably serve such high demands.

Figure 17



Existing generation in the ERCOT Interconnection is capable of sustaining projected demand growth through 2005 (Figure 18). Even if demand growth is at the high side of the bandwidth, ERCOT's existing generation could sustain the growth through 2003.

Figure 18

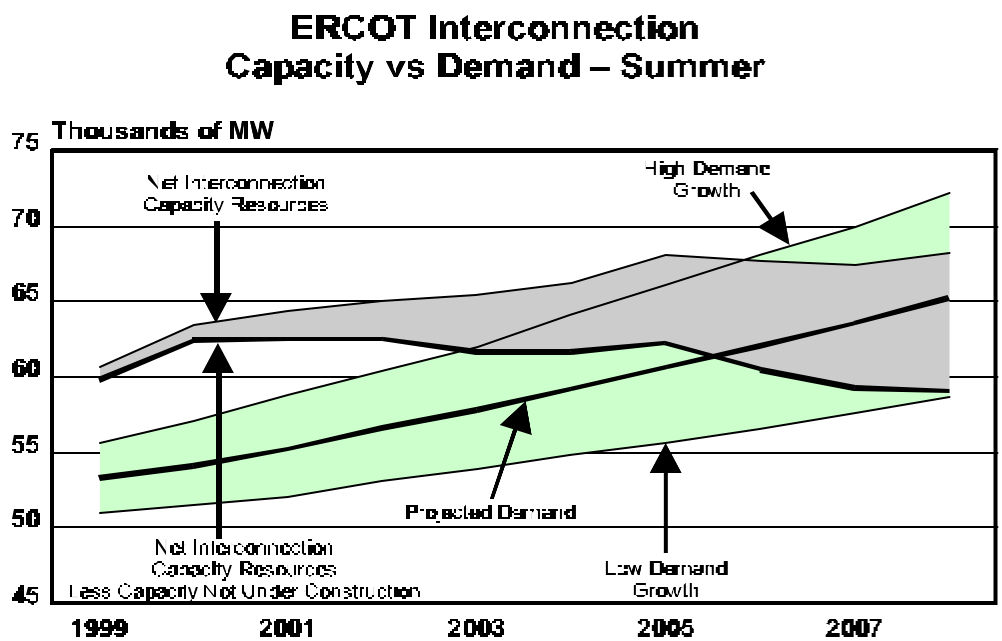


Figure 19

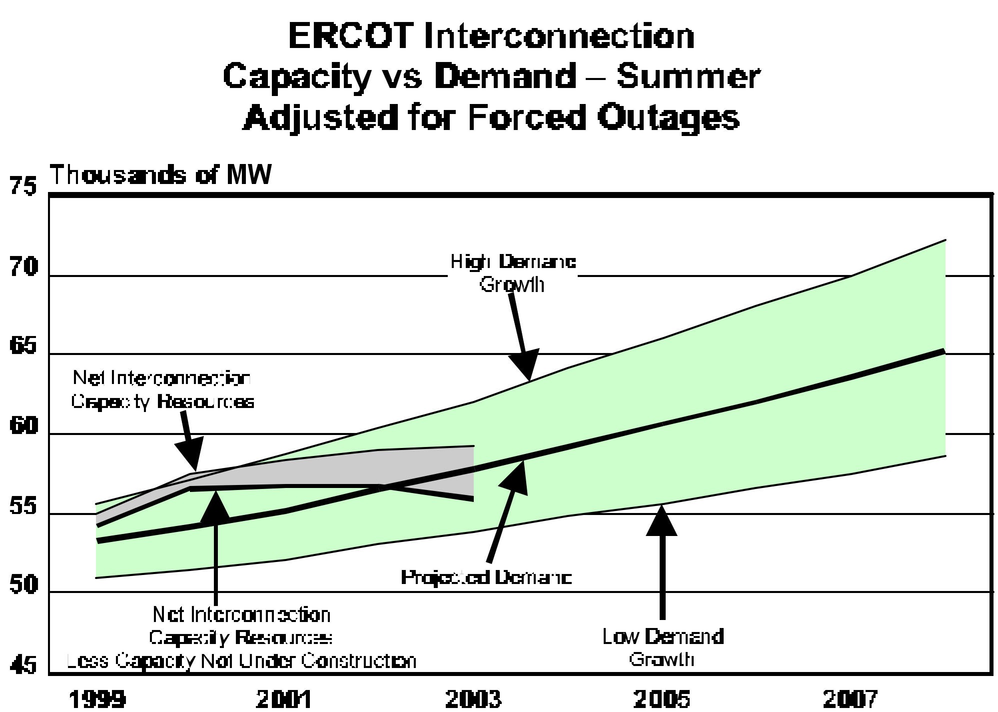
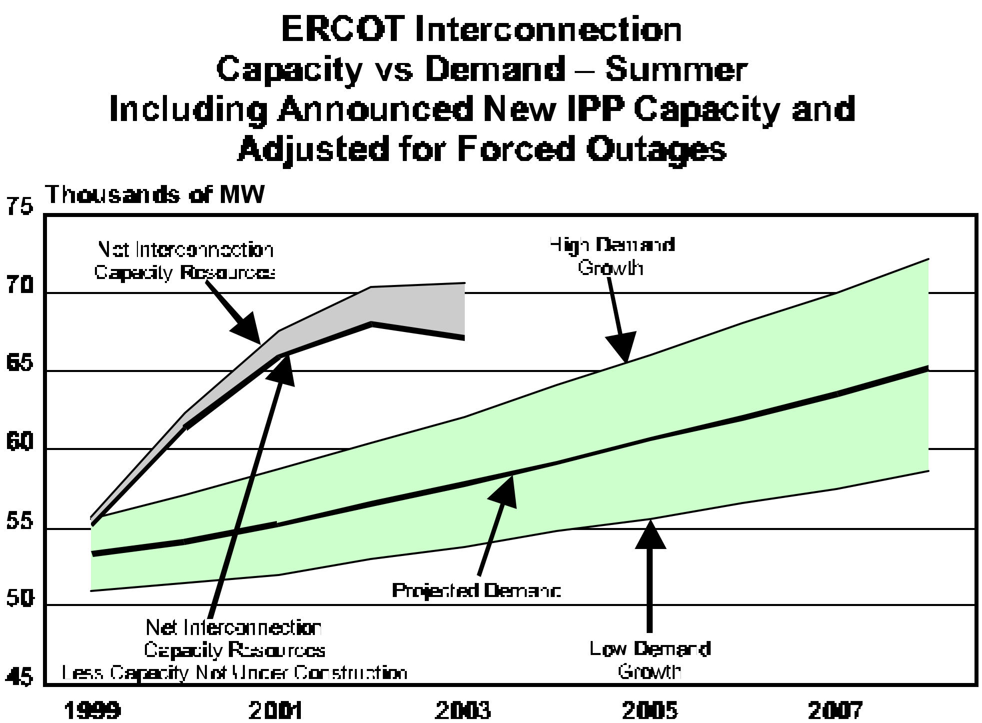


Figure 19 shows the effects of the average summer generation forced outage rate (9.9%). Even with the forced outages, the existing ERCOT generation can sustain the projected demand growth through 2002. It also can sustain the high-end demand bandwidth growth rate through 2001. With the reported planned capacity additions, high growth bandwidth can be sustained through 2002.

Over 20,000 MW of new generating capacity proposals have been submitted to the ERCOT ISO for Interconnection analysis. While not all of this proposed capacity is reported as "under construction," it reflects the expectation of generating entities to build new capacity in the Region.

EPSA has also identified about 10,200 MW[7] of additional merchant capacity announced for construction in ERCOT by the end of 2001. That amounts to over a 16% increase in installed capacity in the Region. Figure 20 shows the marked increase in capacity margin resulting from the additional announced merchant capacity.

Figure 20



7 All EPSA generation values are as of September 1, 1999, to be more consistent with the 1999 demand forecasts produced in April 1999. Substantial amounts of new merchant capacity announcements have been made since that time.

Table 4 — ERCOT Interconnection – Summer

	1999	2000	2001	2002	2003
Projected Interconnection Internal Demand	53,330	54,199	55,173	56,623	57,845
Interconnection Interruptible Demand & DCLM	3,076	2,877	2,908	2,936	2,960
Projected Interconnection Net Internal Demand	50,254	51,322	52,265	53,687	54,885
Projected Interconnection Generating Capacity	59,666	62,550	63,365	64,115	64,439
Interconnection Tie Capability	940	940	940	940	940
Net Interconnection Capacity Resources	60,606	63,490	64,305	65,055	65,379
Interconnection Margin	10,352	12,168	12,040	11,368	10,494
Interconnection Capacity Margin (%)	17.1	19.2	18.7	17.5	16.1
Net Interconnection Capacity Resources Less Capacity Not Under Construction	60,606	63,490	63,555	64,005	63,579
Projected Capacity Additions	–	–	750	1,050	1,800
Projected Capacity Additions as % of Projected Internal Demand	–	–	1.4	2.0	3.3
Projected Capacity Additions as % of Capacity Margin	–	–	6.2	9.2	17.2
Announced New Merchant Capacity	1,000	5,385	10,210	12,510	12,510
Net Interconnection Capacity Resources Plus Merchant Capacity	61,606	68,875	74,515	77,565	77,889
Interconnection Margin Adjusted for Announced Merchant Capacity	11,352	17,553	22,250	23,878	23,004
Interconnection Capacity Margin Adjusted for Announced Merchant Capacity (%)	18.4	25.5	29.9	30.8	29.5
Projected Interconnection Net Purchases	122	136	137	137	133
Projected Interconnection Net Purchases as % of Projected Internal Demand	0.2	0.3	0.2	0.2	0.2
Projected Interconnection Net Purchases as % of Interconnection Tie Capability	13.0	14.5	14.6	14.6	14.1

Table 4 — ERCOT Interconnection – Summer (continued)

	2004	2005	2006	2007	2008
Projected Interconnection Internal Demand	59,182	60,708	62,117	63,588	65,210
Interconnection Interruptible Demand & DCLM	2,982	3,004	3,023	3,044	2,956
Projected Interconnection Net Internal Demand	56,200	57,704	59,094	60,544	62,254
Projected Interconnection Generating Capacity	65,187	67,187	66,813	66,460	67,343
Interconnection Tie Capability	940	940	940	940	940
Net Interconnection Capacity Resources	66,127	68,127	67,753	67,400	68,283
Interconnection Margin	9,927	10,423	8,659	6,856	6,029
Interconnection Capacity Margin (%)	15.0	15.3	12.8	10.2	8.8
Net Interconnection Capacity Resources Less Capacity Not Under Construction	63,577	64,327	62,453	61,350	61,058
Projected Capacity Additions	2,550	3,800	5,300	6,050	7,225
Projected Capacity Additions as % of Projected Internal Demand	4.5	6.6	9.0	10.0	11.6
Projected Capacity Additions as % of Capacity Margin	25.7	36.5	61.2	88.2	119.8
Announced New Merchant Capacity	12,510	12,510	12,510	12,510	12,510
Net Interconnection Capacity Resources Plus Merchant Capacity	78,637	80,637	80,263	79,910	80,793
Interconnection Margin Adjusted for Announced Merchant Capacity	22,437	22,933	21,169	19,366	18,539
Interconnection Capacity Margin Adjusted for Announced Merchant Capacity (%)	28.5	28.4	26.4	24.2	22.9
Projected Interconnection Net Purchases	133	139	140	141	142
Projected Interconnection Net Purchases as % of Projected Internal Demand	0.2	0.2	0.2	0.2	0.2
Projected Interconnection Net Purchases as % of Interconnection Tie Capability	14.1	14.8	14.9	15.0	15.1

Transmission Adequacy and Security Assessment

The transmission system of North America is expected to perform reliably at least in the near term. Procedures and processes to mitigate potential reliability impacts appear to be working effectively for now. However, the loadings on the transmission system are increasing as customer demand for electricity increases and as the system experiences new loading patterns resulting from open transmission access.

Recently, the adequacy of the bulk transmission system has been challenged to support the movement of power in unprecedented amounts and in unexpected directions. This is largely the result of the evolution of the electric industry under open transmission access, particularly when the market is trying to supply replacement resources during unplanned generation outages. These changes in the use of the transmission system have called into question the adequacy of the transmission system. While the system is adequate under the traditional definition, the system may not always be able to accommodate desired transfers of electricity in directions and amounts for which it was not designed.

The transmission system is being subjected to flows in magnitudes and directions that have not been studied or for which there is minimal operating experience. New flow patterns result in new 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.

Voltage problems experienced in ECAR, SERC, and MAAC during the 1999 summer peak demands and heavy transfers indicate that reactive support enhancements are needed to the transmission system to maintain adequate voltage and prevent voltage instability. The character of the demand being served at the time of summer peak is changing. Summer demand peaks are becoming largely dominated by air conditioning, which draws reactive power from the electric system. Distribution systems must maintain adequate reactive power support to keep the increasing air conditioning and other inductive demands from creating voltage problems for the overall system.

Similarly, transmission owners must supply adequate reactive power to maintain voltage stability during heavy transfers of electricity, regardless of the local demand level at the time of the transfers. The ability to transfer energy across some interfaces may be hampered without sufficient reactive power support enhancements to the transmission system. Distribution systems must also keep pace with shunt capacitors additions to avoid depending on the transmission system for reactive support. There are indications that backup reactive power is also needed to replace the reactive power lost when key generating units are forced out of service. These reactive power support activities must be coordinated and the systems must be far more versatile to accommodate the widely varying flow patterns and associated reactive demands that have become commonplace with open transmission access.

As the demand on the transmission system continues to rise, the ability to deliver energy from remote resources to load centers is deteriorating. New transmission limitations are appearing in different and unexpected locations as the generation patterns shift to accommodate market-driven energy transactions and new merchant generators. Delivering energy to deficient areas and in any direction and amount that market forces desire has become more difficult and, at times, not possible.

In the long term, transmission providers need to rethink their systems in terms of open access transmission potential uses, including planning for necessary reactive support. Business is increasing on the transmission system, but very little is being done to increase the load serving and transfer capability of the bulk transmission system. Most of the transmission projects planned over the next ten years are intended to reinforce parts of the system to alleviate local problems.

Table 5 — Planned Transmission

	Transmission Circuit Miles 230 kV and Above			
	1999 Existing	1999-2003 Additions	2004-2008 Additions	2008 Total Installed
ECAR	15,976	248	212	16,436
FRCC	6,580	272	155	7,007
MAAC	7,031	69	109	7,209
MAIN	5,592	131	–	5,723
MAPP – U.S.	15,138	42	–	15,180
MAPP – Canada	5,846	240	242	6,328
NPCC – U.S.	6,456	203	19	6,678
NPCC – Canada	28,732	497	16	29,245
SERC	28,068	401	188	28,657
SPP	7,212	556	336	8,104
Eastern Interconnection	126,631	2,659	1,277	130,567
WSCC – U.S.	56,606	1,164	891	58,661
WSCC – Canada	10,543	47	80	10,670
WSCC – Mexico	431	39	–	470
Western Interconnection	67,580	1,250	971	69,801
ERCOT Interconnection	7,032	710	111	7,853
United States	155,691	3,796	2,021	161,508
Canada	45,121	784	338	46,243
Mexico	431	39	–	470
NERC Total	201,243	4,619	2,359	208,221

Only 6,978 miles of new transmission (230 kV and above) are planned throughout North America over the next ten years. This represents only a 3.5% increase in circuit miles. Newly announced transmission projects have resulted in an increase (400 circuit miles) over last year's projection.

Four significant EHV transmission projects have been proposed in ERCOT through the ISO's planning process. Those projects are funded by a unique Texas-mandated cost-sharing formula for transmission projects. However, it is not yet clear if appropriate incentives exist in all Regions to encourage transmission system additions and reinforcements to support the needs of the competitive market. New Regional planning entities and approval processes must also be developed to deal with the need for new transmission lines for an open market.

Additional issues affecting the reliability of the North American transmission system are explored in the Transmission Issues section of this report.

RELIABILITY ISSUES

A number of new reliability issues are facing the electric industry in North America as it continues its transition to an open market. To understand what issues may impact reliability in the future, it is important to understand the history and current state of the bulk electric system. The changes also are occurring during a period of declining capacity margins caused by increasing demand and forecast uncertainty, coupled with a lack of substantial generation capacity additions over the last few years. At the same time, a strong economy in North America continues to prompt strong demand growth. The emergence of merchant power market and the divestiture of generation capacity by traditional utilities have substantially changed the resource supply function, introducing additional supply-side uncertainty.

Restructuring also has resulted in a sharp rise in the number, direction, and magnitude of energy transactions, which are increasingly changing the flows on the transmission system. Furthermore, transmission use has dramatically increased as demand continues to grow with few substantial additions to the transmission system.

Year 2000 Transition

A challenge to electric reliability throughout the world was the transition to the Year 2000 (Y2k) because certain organizations in the electric and other industries use software and hardware that use a two-digit code to represent the last two digits of the year. As a result, these software and hardware could have possibly misinterpreted the change from 1999 to 2000.

Y2k Preparations in the Electric Power Industry

The U.S. Department of Energy (DOE) asked NERC in May 1998 to assume a leadership role in preparing the electricity production and delivery systems of the United States for Y2k. DOE's request was part of a broad initiative by the government to ensure that infrastructures essential to the nation's security and well being remained operational during critical Y2k transition periods. Due to the interconnected nature of the electric systems in North America, NERC expanded the scope of its coordination efforts to include power systems in the United States, Canada, and the northern portion of the Baja California Peninsula in Mexico.

NERC has now closed the chapter on one of its greatest challenges ever in response to the DOE request. The end of year rollover to the new millennium is now history and the electric power industry has been widely praised for the outstanding results it achieved.

Details on NERC's efforts for Y2k preparation can be found in a series of reports entitled *Preparing the Electric Power Systems of North America for Transition to the Year 2000*, which can be downloaded from the NERC Y2k web site on the Internet at: http://www.nerc.com/~y2k/.

The reports describe the industry's efforts to prepare electric power supply and delivery systems of North America for operation into the Year 2000, and the systematic process used to achieve and document that readiness.

The overwhelming positive results to date can be directly attributed to the thorough preparations undertaken by the electric power industry with the leadership demonstrated by NERC. On August 3, 1999, NERC delivered to DOE the fourth in a series of quarterly reports on efforts to prepare electric power supply and delivery systems of North America for operation into the Year 2000. This report stated that NERC believed the electric systems in North America would operate reliably into the new millennium based on the state of readiness of the industry at the time of the report. NERC also took the unprecedented step in August of publicly disclosing those 251 entities it believed had met NERC criteria for having mission-critical electric systems Y2k Ready or Y2k Ready With Limited Exceptions. A follow-up report was delivered to DOE in mid-November 1999, providing closure on remaining Y2k issues. By early December, the electric industry was able to proudly report that all electric supply and distribution entities in North America were now Y2k ready; the entities on NERC's Y2k Ready list in the interim increased to 302.

NERC worked with DOE to conduct random audits of utility Y2k programs to independently verify the accuracy of the data and Y2k readiness of the industry. In all, 56 audits were conducted. The reports discussing these audits can be found at: http://www.NERC.com/y2k/audits.html.

By addressing the Y2k issue in a positive and aggressive manner, the electric power industry effectively reduced risks to society associated with Y2k. This investment was one that the industry was obligated to make and there would have been no tolerance for anything less. At the same time, there are many collateral benefits to the industry and the public in terms of improved, tested electronic systems and enhanced operational readiness during emergencies.

One of the more lasting benefits of Y2k for NERC may be the high level of cooperation it received from the American Public Power Association, Canadian Electricity Association, Edison Electric Institute, Electric Power Research Institute, Electric Power Supply Association, National Rural Electric Cooperative Association, and the Nuclear Energy Institute. Each of these organizations contributed significantly and unselfishly to a common effort for the benefit of the industry.

Regulatory and Organizational Changes

NAERO and Legislation

NERC is in the process of "reinventing" itself into the North American Electric Reliability Organization (NAERO). The NERC Board of Trustees has elected nine new independent members. Adding these new independent members to the existing Board of 37 "stakeholders" represents a bold step in the continuing transformation of NERC into an independently governed, self-regulating organization that will set and enforce compliance with reliability standards throughout North America. On February 1, 1999, the NERC Board of Trustees approved consensus legislative language on reliability. That language has formed the basis for the reliability section in several electric restructuring bills introduced in Congress, including the bill proposed by the Administration. Stand-alone legislation has also been introduced in both the House and the Senate containing the consensus legislative language on reliability. The legislation would authorize the creation of an independently governed, self-regulating organization with the Federal Energy Regulatory Commission providing oversight in the United States. Under the legislation, reliability standards would be enforceable for all owners, operators, and users of the bulk power system. Although there is considerable activity in Congress, the timing for passage of reliability legislation remains uncertain, due to other issues in the electric restructuring debate.

FERC

In December 1999, FERC issued its final rule on development of regional transmission organizations (RTOs). The intent of the rulemaking is to facilitate the formation of RTOs. The Commission established minimum characteristics and functions that a transmission entity must satisfy to be considered an RTO. The Commission describes four minimum characteristics of an RTO: independence; appropriate scope and regional configuration; sufficient operational authority; and responsibility for short-term reliability. The Commission describes eight minimum functions that an RTO must perform: tariff administration and design; congestion management; management of parallel path flow; provision of ancillary services; maintain OASIS and calculate total transfer capability and available transfer capability; market monitoring; planning and expansion; and interregional coordination.

The rule requires each jurisdictional utility to make filings with the Commission either demonstrating its participation in an RTO that satisfied the minimum requirements, describing its efforts to form an acceptable RTO, or explaining its reasons for not doing so, and its future plans. The Commission expects that RTOs meeting the minimum characteristics and functions would begin operating the transmission facilities no later than December 15, 2001.

In response to a FERC Order in late 1998, NERC developed revised transmission loading relief (TLR) procedures, including:

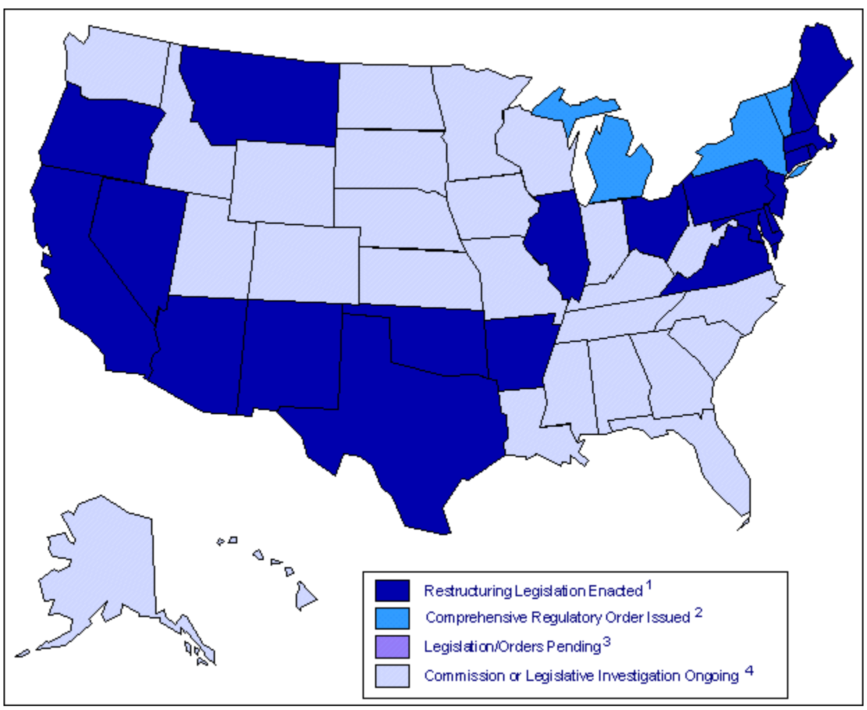
- An additional step in the TLR procedure to calculate the share of a transmission constraint that is attributable to transactions using firm point-to-point transmission service (transaction contribution factor). The security coordinator will determine this share from the NERC Interchange Distribution Calculator (IDC). The assumption will be made that the remaining share of the constraint will be due to native load and network service.

- A pilot market redispatch program for common constraints within the Eastern Interconnection. This pilot provides a redispatch alternative through the use of bilateral redispatch options that are pre-arranged by the transmission customer and individual generation owners.

In addition, the NERC Market Interface Committee will develop a plan for addressing longer-term, congestion management solutions.

State Issues

Most states and the District of Columbia adopted or are contemplating their own industry restructuring plans. Several states and local government organizations are urging Congress to let states handle most of the restructuring issues. Some states that already opened their retail markets to competition are concerned that federal legislation will undermine their efforts. Congress and the Administration indicated a willingness to grandfather existing state restructuring plans. The map below shows the current status (March 2000) of state restructuring initiatives.



Provincial Issues

In Canada, reliability management has been the primary responsibility of the utilities, which developed their own standards or participated in developing voluntary reliability standards through NERC. Although NERC's standards are recognized by the utilities as the industry standard in Canada, each provincial government must grant authority to NAERO as the proposed mandatory compliance organization.

The National Energy Board's major role in reliability has been to approve construction and operation of international power lines. In many cases, provincial regulators have had broad jurisdiction to ensure that the electricity system is operated in a safe and reliable manner, to approve applications for new generation or transmission facilities, to approve rates, or to impose operating restrictions on transmission facilities. In all provinces, except Saskatchewan, provincial regulators oversee electric utility activities.

In the provinces of Alberta and Ontario, responsibilities for reliability are clearly established as part of the regulator's mandate. In Alberta, under the Electric Utilities Act, the transmission administrator has a responsibility for reliability management. The transmission administrator is responsible to set standards and requirements for system support services, and to make arrangements for those services. The transmission administrator also may incorporate charges for those services into the tariff. The Alberta Energy and Utilities Board must approve such tariffs. In Ontario, under recent restructuring legislation, the Ontario Energy Board will be an independent regulator for the electricity industry. The independent market operator will make market rules, including reliability rules, which are subject to oversight of the Ontario Energy Board.

The reliability role varies in the other provinces. In British Columbia, under the Utilities Commission Act, the British Columbia Utilities Commission has authority to make orders about matters it considers necessary or advisable for the safety, convenience, or service to the public. In Québec, the Régie de l'Énergie has jurisdiction to monitor the operations of Hydro-Québec to ascertain that consumers are adequately supplied with electricity. In Manitoba, Manitoba Hydro may set standards and rules for the reliability of the transmission and distribution lines, and may refuse to connect any distribution or transmission line if the line is not operated in accordance with those standards.

Resource Adequacy

The electric industry may undergo a significant change in reliability during the transition from the historical capacity resource-planning paradigm to one driven by market forces. Even the very levels of resource reliability that customers have come to expect may change. Customers may be willing to accept periodic interruptions of electric service in exchange for lower rates. During the transition, the challenge will be to maintain the balance between supply and demand by allowing clear market signals to encourage development of adequate new resources, transmission system support, and demand-responsive customer programs.

Capacity Plan Uncertainty

The transition to a competitive market may present reliability concerns because sufficient capacity may not be constructed in time to keep pace with demand growth in all areas. Traditional vertically integrated utilities have been hesitant to build rate-based plants and transmission capacity and, in some areas, competitive markets may not have matured sufficiently to attract merchant generation development. For the most part, utilities are no longer committing to build new large-scale, long-lead-time generation projects. Instead, they are relying on either purchasing capacity from the market or possibly constructing smaller, short-lead-time (two to three years) combustion turbine and combined-cycle plants themselves. Long-term assessment of resource adequacy has become very difficult due to the uncertainty of capacity plans beyond a planning horizon that has effectively been shortened to about three years.

The growing trend is to rely on purchases from the wholesale markets to serve firm customer demand. Such purchases rely on the capacity margin of others and demand diversity within the Interconnection, and the transmission transfer capability to import those resources. If the majority of load-serving entities assume they can purchase from the market on an ongoing basis without building any generation, the total physical (generation on the ground) capacity margin of the Interconnection can rapidly deteriorate to undesirable levels. Clear market price signals will be necessary to both encourage new generation capacity and demand responsiveness. There is risk associated with over reliance on demand diversity due to transmission system limitations, which could cause the delivery of these resources to be curtailed. Forced outages of generation during the last few summers in MAIN and New England demonstrated the potential for deliverability problems even for replacement or current capacity resources. Such delivery problems are indicative of possible problems for importing external resources in the future.

Role for Competitive Power Suppliers

The incremental capacity and energy market itself is being increasingly supplied by competitive power suppliers, including merchant generation developers. This increasingly competitive atmosphere has substantially changed the traditional resource supply function, introducing additional supply-side uncertainty for future capacity adequacy. Some areas of North America are more attractive than others for market-driven generation development.

In some areas, there is little incentive to build because new gas-fired units may not be competitive with the low marginal costs of the existing generating capacity. In addition, the absence of retail competition in an area may discourage the development of merchant generation because there are fewer potential buyers. As the demand continues to grow and capacity margins in those areas decline, there will be an increasing need to import additional resources. Market price signals from those areas will be relied on to entice generation development. If the demand growth is unusually high, or generation outages occur within those areas, the need to import resources may outstrip the transmission import capability before the new generation can be placed in service.

In other areas, generation developers' plans for new capacity greatly exceed the need for the resources. For example, developers have announced plans to potentially develop over 30,000 MW of capacity in New England (principally combined cycle). The region presently has generation resources of about 24,500 MW and a peak demand of about 23,000 MW. Developers are apparently expecting the efficient combined-cycle plants to replace high-cost oil/gas steam plants, which total only 4,000 MW. Building all 30,000 MW does not appear to be realistic or justified, and not all of the announced capacity will be built. It is expected that the most efficient units will survive the competitive screening process, thereby ensuring that the lowest cost, most reliable alternative will be developed. Ultimately, the market process should result in new generation construction that will roughly equal the projected demand growth.

What makes certain areas more attractive for new capacity development? There are many factors, often working in combination, including:

- A need for generation capacity increases — Areas in immediate need of generation resources with low capacity margins, particularly with periodic shortfalls, are attractive for development.
- The ability to displace older, high-priced, inefficient generation — Advanced technology combustion turbines and combined cycle units are often more efficient and cost effective than old gas- or oil-fired generators.
- Replacement of capacity being retired — The impending retirement of nuclear generation in New England during the last few years provided strong incentives for new capacity construction. On the other hand, nuclear outages in the MAIN Region did not spark as strong a response from the market because those units were expected to return to service.
- Transmission constraints create a closed market — If transmission constraints prevent significant imports of low-cost power into an area, developing internal generation can be more profitable.

- Ease of connection and fuel availability — Ease of connecting to the electrical transmission system and stable fuel supplies make certain sites far more attractive for development.
- Predictable regulation — Areas where the regulatory environment is amenable to generation development are more attractive.
- Market rules that provide consistent, predictable economic outcomes — Areas where there is regulatory assurance of transmission interconnection and other procedures and other requirements provide a more stable commercial environment for development.
- Retail competition — Areas where retail competition programs are in place present a significant new potential for buyers of bulk power, allowing the entry of large aggregators of retail load, large industrial, and commercial customers.

Competitive suppliers also are purchasing existing generation from traditional utilities as generation assets are divested either in utilities positioning to be more competitive or in response to regulatory mandates for open access. Most of the divested capacity remains under contract for some period to the selling utility. Therefore, there is little or no near-term impact on supply adequacy or the operation of the system. However, divestiture raises some issues regarding long-term resource adequacy, operations, and how reliability should be assessed:

- Reallocation of capacity resources — As the initial contracts for the divested capacity expire, those resources will be committed by their new owners, possibly to other customers. The original owners too may seek other suppliers, possibly remote from their immediate control area. Adequacy analysis methods must be able to account for that reallocation of resources, and determine any potential impacts on expected transmission loadings or limitations.
- Maintenance coordination — The merchant generator community has proven its ability to adequately maintain its generation. Financial incentives will remain high to keep the newly acquired plants operating at peak efficiency and availability. However, as the merchant producers' share of generation grows, coordination of maintenance outages with the needs of the overall system may become a problem. For example, a number of merchant plants may simultaneously take maintenance outages in preparation for the peak season. If too many plants are taken off-line simultaneously in a given area, it may leave the system vulnerable to local capacity shortages or transmission support problems. Some outage coordination may be appropriate through an ISO, RTO, or security coordinator to guard against creation of inadvertent operational problems.
- Operation and retirement of generators critical to transmission support — Some of the generating plants being acquired by the competitive suppliers have a critical role in support of the transmission system. Such units should be designated as "must-run" in current and future contracts. Those generators must also be appropriately recognized and compensated for their role as providers of ancillary services to the transmission system. For the long term, any potential retirement of those critical units must be able to trigger plans for replacing their voltage support with new generation or other appropriate equipment.
- Repowering of older generators and efficiency gains — Many merchant developers buying older generating plants are planning to repower the acquired generators and/or add new capacity to those sites. This may result in additional efficiencies at those generation stations.

These issues will have to be addressed to ensure continued contribution of divested generation assets to the reliability of the overall system.

Changing Role for Interruptible Loads and Direct Control Load Management

The role of interruptible loads and direct control load management in maintaining the balance between resources and demand may be changing as the industry moves to an open marketplace. Given the right financial incentives and signals, contractually interruptible loads could become as important to the resource and demand balance as the addition of new generation.

In today's regulatory and market environment, load-serving entities may have far less direct control over the sufficiency of their power supply. Consequently, when the demand increases dramatically and the power supply has not kept pace, there is potential for wholesale electricity price volatility and the possibility of having to interrupt service to firm customers to maintain the supply/demand balance. Fortunately, over the last two summers, the tight capacity situations have only resulted in price volatility and voluntary curtailment of firm customer demand following public appeals to reduce usage.

Traditional utility "obligation to serve" customers were subject to the implicit qualification of serving "at any price." Very little, if any, financial impact was visible to consumers from the wholesale electricity price spikes of the last two summers. Consequently, the load-serving entities are left with an inelastic demand curve that puts them at increasing risk of having to pay extremely high marginal costs during high demand periods when they may have to keep buying, regardless of price. Although price volatility may encourage generating capacity additions, they can be devastating to market participants that are not prepared to accept the financial risk or cannot recover the extra costs in their regulated rates.

One potential solution to this problem is to expose more customers to real-time market prices. Many customers may be willing to absorb more price uncertainty, and even more supply uncertainty, in exchange for lower overall rates. Such arrangements are not unusual for industrial and commercial interruptible contracts today. With improving technology and telecommunications, real-time pricing could become economical for smaller customers as well, perhaps even residential customers. Offering customer's price-based interruptibility as one of their service options under retail access has already happened in the province of Alberta, Canada. Alberta's resources for the 1999 summer included 362 MW (over 5% of system peak demand) of "price responsive demand" that is contractually interruptible.

Such price-based interruptible demand, coupled with existing interruptible contracts in the industrial and commercial sectors, could offset the need for some additional generating capacity. When organized into dispatchable blocks controlled by the system operators, price-based interruptible demand could become a very useful operational tool for maintaining reliability.

Reliance on Natural Gas

Although coal is still used for most electricity generation, natural gas is clearly the fuel of choice for the capacity additions reported for installation in the next ten years. About 90% of the announced new generating capacity will be fired by natural gas. According to information provided by the Energy Information Administration, the electric utility sector was the only end-use sector to show strong growth in 1998 when gas consumption rose by 11% over 1997. This trend is expected to continue and accelerate. Gas turbine technology continues to advance, making new efficient gas generation more cost effective than other sources, including some existing generation. Natural gas has long been an environmentally preferred fuel because of its low emission characteristics. Finally, these units can be manufactured, sited, and constructed in less time than competing technologies. All of these desirable features have led to the emergence of natural gas as the preferred fuel for new electric generation.

The varying degrees of firmness of the gas commodity and its associated transportation are often not reflected in electrical system capacity analysis and reliability assessments. For example, some capacity resources may be counted as firm in a capacity analysis when their associated gas supply is interruptible. As gas-fired generation becomes a larger component of the overall resource mix, this issue will grow in importance.

Loss of Major Gas Transmission Pipelines into a Region

An increased reliance on gas as a primary fuel for electricity generation creates a stronger interdependence between the electric and gas industries. The dependence on natural gas for the new gas-fired generation creates a similar dependence on the natural gas transmission system to deliver the fuel to the generation sites. In areas where there are large concentrations of natural gas-fired generation, could an interruption on the gas transmission system trigger a significant loss of electric generation capacity?

An investigation of the gas transmission system and its overlay onto the electricity generation facilities was made. Although there are areas, such as south Texas and New York City, where there are significant concentrations of gas-fired generation, a substantial network of gas transmission facilities also exists to support these generating facilities.

Of greater concern are areas with significant gas-fired generation, which are at the farther reaches of the gas transmission system. Based on these criteria, more detailed investigations were conducted for Florida and New England.

Florida

Florida is currently served by three gas transmission systems — South Georgia Natural Gas Company, Koch Gateway Pipeline Company, and Florida Gas Transmission Company (FGT). The latter has by far the largest system, starting at the Alabama border, serving most of the state, and terminating in the Miami area. Along this system are about 7,200 MW of gas-fired generation. This capacity represents about 19% of Florida's generation resources. A large portion of this generation is composed of gas turbines that are mainly used during peak demand conditions. Loss of gas supply to these generators during the peak would not cause significant problems because, in almost all cases, these generators can use fuel oil as a backup fuel source. Also, it must be recognized that the pipeline system is more than one pipe (the interface on the flowgate system at the Alabama border is actually three pipelines). So, even though the exposure is significant, the probability of loss of the gas system is very low. Coupled with the availability of alternative fuels and three new pipelines into Florida seeking regulatory approval, the continued reliability of the gas-fired generation in Florida appears acceptable.

New England

The New England area is currently served by about seven gas transmission systems. Algonquin Gas Transmission Company and Tennessee Gas Pipeline Company have the largest systems, which traverse the area from New York to eastern Massachusetts. However, in contrast to Florida, no large concentrations of gas-fired generation exist on any one system. About 3,400 MW of gas-fired generation is in New England, and represents about 16% of the area's generating resources. The generators are more evenly distributed in the New England area than in Florida. Based on the current amount of generation and its location on the gas transmission system, it would appear that a gas supply disruption causing significant problems in the electric system of New England is a very low probability event. However, the critical role of the gas system to support heating demand in New England during the winter season cannot be ignored. If a gas system curtailment forced the choice to support heating or electricity generation, based on past experience, residential heating is typically given priority due to the potential life threatening impact. Ironically, most heating systems require electricity to run the blower fans, circulating pumps, and controls, rendering them inoperative without electricity.

The New England area has a large amount of planned gas-fired generation. Various reports indicate that planned generation could exceed the current total gas resources of the area. Although development of such a large amount of generation is unlikely to occur, little doubt exists that significant amounts of new gas-fired generation will be constructed in the area during the next ten years. The ability of the gas transmission system to support this additional generation should be monitored. New

England and the Northeast have only minimal gas storage and reserves. Any additional demand will have to be provided by the interstate pipelines. According to the *1998 Natural Gas: Issues and Trends* report, published by the EIA, almost no new capacity additions are planned for the northeastern systems that would increase the gas pipeline import capability to New England.

The natural gas industry does not publish readily available reliability data on the interstate gas transmission system. Also, no organization exists in the gas industry that is comparable to NERC. Given the significant and growing reliance of the electric industry on the gas industry, the two industries need to work together to better understand the impact that each has on the other.

Reliability Impacts of Environmental Regulations

Environmental legislation and regulatory measures are continually proposed at the federal, state, and Regional levels that would place limitations on emissions of carbon dioxide and mercury, and would tighten emissions caps on sulfur dioxide (SO_2) and nitrogen oxide (NO_x). The Environmental Protection Agency (EPA) and the Administration also are trying to develop programs to meet the restrictions on greenhouse gases embodied in the Kyoto Protocol. The potential for reliability impacts on the electric system of any such proposed measures must be analyzed carefully and understood before new rules or programs are put in place.

Reliability Impacts of the EPA NO_X SIP Call

RAS recently directed a study to ascertain the incremental impact on electric system reliability of the U.S. EPA final rules for nitrogen oxide (NO_x) emissions that will require electric generators in a 22-state area to comply with Regional emission limits beginning with the 2003 ozone season (State Implementation Plan, SIP Call). The full report is available on the NERC web site at: http://www.nerc.com/~filez/ras.html.

Regions primarily affected are ECAR, MAIN, MAAC, and SERC. The emission limits will require installation and use of new equipment and processes at a number of generating stations in these states. One of the new equipment/processes is selective catalytic reduction (SCR), which requires some extension of planned generation maintenance outages to accomplish the retrofits. These extended planned outages potentially could degrade reliability.

Analysis of the potential impacts to reliability through computer simulations indicated that the incremental adverse impact of the SIP Call on reliability in the NERC Regions[8] that comprise the 22-state SIP Call area, range from not significant to cause for concern. In particular, small impacts were identified in the MAAC and SERC Regions. However, there were some scenarios in ECAR and MAIN that produced significant impacts or cause for concern.

Range of Impacts	
Not Significant	No differences, or if there are, the differences are not noticeable to operations.
Significant	Difficult to manage operationally, but may be mitigated through longer-term planning (i.e., season ahead to one year ahead).
Cause for Concern	Real differences that may be operationally manageable through emergency procedures and/or short-term planning.

8 The study results for the reference scenarios do not compare well with reliability studies performed by the ECAR and MAIN Regions. The analysis resulted in some loss of load expectation (LOLE) values considerably greater than either Region might otherwise expect. However, because a consistent methodology, assumption, and model were used in assessing the two Regions, this study is appropriate for assessing the relative reliability impacts caused by the SIP Call between and among the Regions impacted by the SIP Call.

In addition to the analysis on the impact of capacity additions, analyses were performed for ECAR and MAIN to determine the sensitivity of the results to variations in other factors, the degree of planned maintenance outage coordination, length of the retrofit window, and the SCR retrofit outages assumed. The analyses indicated that adverse impacts could be at least partially mitigated through the application of increased maintenance outage coordination within the Regions and/or commencement of the retrofit program in 2000 or 2001.

Based on the result of the analyses, it logically follows that any reduction in the amount of SCR equipment needed for compliance, or extension of the retrofit window, would lessen the adverse impacts of the NO_x SIP Call. Application of alternative NO_x reduction technologies that do not require additional generation outage time for retrofits might reduce the number of units requiring SCR equipment, thereby reducing the impact of retrofits. Similarly, use of State Supplemental Allowance Credits, proposed by the EPA, could effectively extend the retrofit window, again reducing the SIP Call impacts. Some advanced technologies were considered but not explicitly analyzed because of their limited application not having been applied to units above 600 MW. Use of the allowance credits was not explicitly analyzed because conclusions on its effect can be drawn from the analysis of the length of the retrofit window.

On March 3, 2000, a three-judge panel of the U.S. Court of Appeals for the D.C. Circuit (the court) ruled in the consolidated cases challenging the 22-state SIP Call rule, upholding the rule on most issues. The decision will allow EPA to go forward with its regional NO_x reduction mandate after responding to the remanded issues. The court ruled that EPA acted unlawfully in including Wisconsin, and remanded the full-state coverage of Georgia and Missouri for further consideration. Also remanded for further consideration by EPA were the “redefinition” of “electricity generating unit” to include interconnected generators from which any electricity is sold, and setting emissions budgets on 90% control efficiency for large stationary internal combustion sources. On remand, EPA will need to recalculate state NO_x emission budgets based on the opinion. The ruling did not lift the court’s May 25, 1999 indefinite stay of the requirement for SIP submissions, thus states are not subject to either the September 30, 1999, SIP filing deadline, nor the default penalty of EPA-imposed Federal Implementation Plans. However, on April 11, 2000, the Department of Justice, on behalf of EPA, asked the court to lift the stay, an action that would allow the agency to go forward with the rule for the remaining 20 states. At the same time, EPA also released recalculated budgets without the remanded portions, indicating that it expected SIP submissions to be made by September 1, 2000. Parties could still ask for clarification, a hearing en banc (by the full court), or request a review by the Supreme Court of the March ruling.

Nuclear Generation

Nuclear generation will play an important part in the capacity adequacy of North America for the foreseeable future. Although there is discussion in some European countries of phasing out nuclear power, the overall outlook for nuclear generation in the United States appears to be in relatively good shape. Capacity factors for nuclear plants have been getting better, operating costs are decreasing, average refueling outage lengths are being reduced, and power plant uprating programs and fuel performance improvements have been successful.

However, the North American nuclear industry is not without its problems. Nuclear waste disposal remains an issue in the United States, some utilities are retiring nuclear units early, some plants have been indefinitely “laid up” due to operating problems, and many plants will soon face relicensing.

In some instances, units taken out of service due to problems may not be returned to service but retired instead. Such unanticipated retirement requires replacement of the capacity resource, as was the case of Zion Units 1 and 2 and Millstone Unit 1. About 3,400 MW of Canadian nuclear capacity was “laid up” in 1998 due to operational problems. No timetable has been set to return them to service, effectively removing them from consideration in adequacy assessments.

Almost 3,000 MW of nuclear generating capacity will face relicensing in the United States alone by the end of the ten-year assessment period. In 1998, Calvert Cliffs Nuclear Plant and Oconee Nuclear Plant began the relicensing process, and Calvert Cliffs received authority for relicensing in March 2000. Additional nuclear capacity at Arkansas Nuclear One; Edwin I. Hatch 1 and 2; and Turkey Point 3 and 4 will begin the licensing renewal process over the next 15 months. By 2015, almost 40% of the 103 nuclear units in the United States will face relicensing.

North America's nuclear generation will have to play a vital role to achieve the level of emission reductions called for in the Kyoto Protocol, according to an American Society of Mechanical Engineers task force. For the United States to meet the emission requirements of the Kyoto Protocol it would entail nuclear plant license renewal, the development of advanced nuclear plant designs, the aggressive development of renewables (wind, solar, etc.), the use of advanced coal and gas cycle technologies, the potential addition of nuclear capacity, an increase in energy end-use efficiency, and a slowing in the growth of energy demand.

Analyzing Adequacy

Analyzing capacity resource adequacy is more challenging in the open market. Uncertainties in future generation additions, demand forecasts, and the very way in which data can be collected will require changes to the methods and tools used to analyze the adequacy of future power supply. The uncertainties also will make traditional methods of analyzing future transmission system capabilities more and more difficult because very specific data on generation additions and their location are needed for the transmission simulation models.

NERC and the Regions will have to develop new approaches to perform resource adequacy and future transmission analysis, including an ability to compensate for the added uncertainty. Key to any new approach to analysis will be the use of new methods for demand and generation-addition data collection. The new analysis methods must provide additional reliability-based indicators to support the market price signals that indicate what capacity is needed to serve the projected demand. These indicators should complement the market's price signals for additional resources.

Capacity Plans and Reporting

Although uncertainty in future generation plans has always existed, utilities traditionally reported their best estimates in ten-year or 20-year capacity expansion plans to NERC, DOE, and their state regulators.

In New England, reported capacity plans of the utilities show few generation capacity additions to serve its growing summer peak demand, which is currently about 23,000 MW. However, merchant suppliers have announced over 30,000 MW of generation to be built in that area. Considering only the utilities' plans would lead to the conclusion that New England's capacity is inadequate, while including all of the announced merchant plans would lead to an equally unrealistic conclusion. The most likely outcome will lie somewhere between those two extremes. Therefore, it is very important to carefully analyze the capacity plans of both utilities and merchant suppliers prior to making judgments about overall generating adequacy.

Data confidentiality concerns will require these data be made available only to those entities responsible for analyzing reliability and appropriate government agencies.

Demand Forecast and Reporting

Accurate demand data is essential to the development of demand forecasts used to plan and operate the power system and to assess resource adequacy. The NERC Regions continue to struggle with incomplete reporting of all customer demand within their defined geographic areas. With the advent of open access transmission service to end-use customers in many parts of North America, it has become a more pronounced problem. The power supply responsibility is shifting from a single-franchise utility to competitive power suppliers. With many different suppliers delivering to end-use customers, it becomes an increasingly difficult task to track and report demand growth and generation supply to all of the customers in a Region.

The reliability level of a Region may be very sensitive to demand forecast uncertainty. As that uncertainty increases, reserve margins may have to increase to maintain an equivalent reliability level. In the past, vertically integrated utilities produced forecasts as well as capacity expansion plans needed to assess the reliability of the bulk electric system. In the evolving industry structure, suppliers will be forecasting the market, load aggregators will make separate forecasts for their acquisition requirements, and the "wires" organization will need a forecast of all demands to be connected to its system. Some changes are needed in the data collection and data management practices to ensure that the total demand is accounted for, without double counting or under counting of demand.

Traditionally, demand forecasts were reported from a supply-side perspective, with reporting done by the utility serving the demand in its control area. With the advent of retail access, data collection needs to be developed to account for all end-use customer demand physically connected to the transmission and distribution system, regardless of who is serving that demand.

It is difficult to require the load-serving entity (LSE) to report a demand, which may be aggregated and shown as a demand served from outside the Region. The control area operator is responsible for after-the-fact accounting for demand and capability and often discovers that all the demands have not been properly reported to the Region. This precludes accurate calculation of reserve requirements and responsibilities.

Market Price and Its Effect on Demand and Capacity Forecasting

As long as end-use electricity prices are unresponsive to changing market conditions and utilities retain their regulatory obligation to serve, the wholesale electric market's demand curve will remain almost completely inelastic. In such circumstances, demand forecasts need not consider the additional complicating factor of price sensitivity as end-use customers generally do not see changing prices. However, as margins erode, an inelastic demand curve puts suppliers at risk of having to pay extremely high marginal costs to supply demand during periods of low operating capacity margins. This threat may lead utilities and regulators to increase responsiveness of demand to market conditions (e.g., marginal costs) by promoting real-time pricing, interruptible contracts, etc. Demand forecasting will become more difficult with the incorporation of price elasticity as another variable. All of this uncertainty will be carefully considered by developers that are investing in new generating plants and may lead to a period when it will be more difficult to assess overall reliability using any of the traditional and familiar means.

Reserve Obligations

It is contractually possible to serve a demand and yet retain no obligation to provide reserves. Reserve obligations must be clearly defined to prevent a supply deficit during large generator outages. The absence of such obligations would theoretically require termination of service to a demand if its purchased resource became unavailable. Some Reliability Council's require specific documentation for those types of transactions specifying which entity carries the reserve obligation, the supplier or the customer. Ideally, this process could be carried over to each specific demand point within a transaction that may be a summation of several schedules. This procedure would ensure that each LSE has adequate reserves and will not rely on the other reserves within its control area to make up a deficit.

Self-serve Generation

The issue of who reports the demand, the reserves, and the generation serving the demand becomes especially critical if a particular customer is served by "self-serve" generation that has historically not been reported. This demand and generation may have been transparent to the transmission system, but now may pose a significant reliability threat if it is not accurately accounted for by the control area operator at times when the self-serve generation may be unavailable. In such a case, the reserve issue arises if the control area is expected to continue to serve that demand. Currently, there is no statutory obligation for a company to report either the full demand of a self-serve customer or its generation that is and would normally be transparent to the transmission system. It is during the times that generation is injected into the system, or the generation is unavailable, that a demand or end-use consumer becomes a reliability concern to the Region. The generation patterns of self-serve units may be very unpredictable and vary with market prices. This problem will continue to grow without more stringent reporting requirements for self-serve customers and generation.

Default Suppliers

With the varying types of retail access being developed by the states, the local distribution company may be obligated to provide "backstop" supply to customers whose supplier defaults or is otherwise unable to serve the demand. This vestige of the traditional "obligation to serve" regulatory compact creates an untenable situation for the distribution company by necessitating the carrying of reserves for the customers of others.

A closely related concern is with customers whose demand is served through an interruptible contract who may wish to change to a more reliable service. Many new power supply contracts with interruptible customers are using creative language to provide service that can be interrupted for varying system conditions. They may be interruptible for some circumstances and firm for others, depending on specific contract language. Again, the distribution company must have adequate reserves available unless the customer can be disconnected when its supplier interrupts service.

Although the distribution company may be compensated for providing these services, it is difficult to analyze. Supply adequacy analysis must recognize what reserves are in place and where they are located.

Wider Area Analysis Warranted

Power supply adequacy analysis has included reliance on assistance from others since the first interconnections were made between neighboring utilities. Vertically integrated utilities depended on reserve sharing with neighboring utilities and other assistance over their transmission ties to substantially reduce the need for high installed internal capacity margins. Currently, Regional analyses also make assumptions about the amount and availability of resource assistance from neighboring Regions during generation outages. With the advent of open access and continuing strong demand growth in North America, those assumptions are beginning to be questioned on two fronts: Is adequate generating capacity available from the neighbors, and can it be imported over the transmission system?

Where Will the Capacity Assistance be Available?

Across North America there are areas where the demand continues to grow and generation capacity additions do not keep pace, resulting in a decline in capacity margins. In those situations, the capacity assumed to be available from neighbors must be reexamined. Where the margins of the neighboring systems are also declining, the ability of providing assistance also is diminishing. Static assumptions of external assistance may no longer be valid and must be replaced by probabilistic analysis of assistance from others. At the same time, the open access market has made assistance available from a much wider geographic area. Marketers have played a major role in expanding the assistance horizon. It is not uncommon for Michigan utilities to purchase replacement capacity from Florida. Therefore, assumptions that assistance will only come from immediate neighbors also have to be reconsidered.

Probabilistic resource analysis must be expanded to consider a wider area for possible assistance. To do such analyses will require more Regions to be modeled and may require the development of new computer programs. These analyses also must consider possible transmission system limitations.

Transmission System Limitations May Limit Importing of Reserves

The location of operating reserves is becoming more important. The transmission system is becoming increasingly loaded with flows in magnitudes and directions that were not planned when the system was built. These flows sometimes cause overloads and require use of congestion management to maintain reliability. Consequently, the reserves from neighboring systems may not be deliverable at times to an area requiring them. Therefore, it is becoming increasingly important that potential transmission system limitations be considered when analyzing capacity adequacy and reserve requirements for any given area. These transmission studies also must consider the many possible combinations of transfers that may occur at the time of the import.

Operational Issues

System operators and security coordinators have been increasingly challenged to meet the needs of the evolving competitive electricity markets. They have been directly impacted by the ever-increasing number, distance, and complexity of transactions and the need to handle them while maintaining the reliability of the interconnected electric system. Many new operational tools and skills are needed to deal with the rapidly changing industry. Constant training of system operators will be necessary on new operational tools and to keep abreast of new regulations and standards as they are implemented.

The evolving market and regulations have caused dramatic changes in the way system operators apply NERC Operating Standards in light of FERC regulatory initiatives. The changes are so dramatic that the industry is examining the very philosophy of control areas, rethinking this decades-old concept of matching generation to demand.

Transaction Management Tools

As the number of transactions and their complexity increases, operational administration has become more and more difficult. The sheer increase in transaction volume is staggering. For example, the change in the number of transactions handled by two sample control areas showed an increase of almost 500% over the last four years.

To implement these energy transactions, strict energy scheduling rules must be followed to keep the schedules identified and prioritized. Accurate information must be consistently collected from the market participants and disseminated to other operating/security entities (security coordinators, control areas, and transmission providers) to ensure proper dispatch of generation to implement the schedules. Clear and consistent information and transaction priorities also are required to quickly and effectively implement congestion management or transmission loading relief procedures. To perform these functions adequately under the increasing workload, many new communication, evaluation, scheduling, and accounting tools are needed by system operators. All of those new tools have to be compatible across the Interconnections in which they are used.

Many new tools are being developed by the industry to accomplish these tasks. Some are replacements for functions that may have been manual in the past; others are replacements for systems that are becoming overwhelmed by the new volume of transactions. NERC's electronic tagging (E-Tag) and Interchange Distribution Calculator went into service in the Eastern Interconnection in the fall of 1999, replacing interim tools that were rushed into service in 1997. The Western Interconnection plans to adopt E-Tag in the second quarter of 2000, and the ERCOT Interconnection is looking at the development of a new comprehensive transaction management system.

All of the tools being developed are intended to improve and streamline the management of the interconnected electric systems. One important future enhancement will be the integration of transmission reservation and scheduling with the energy scheduling and transaction tagging process. The concept of "one-stop shopping" will greatly streamline the often frustrating multi-step process faced by the market participants. It will require the cooperative efforts of all industry participants, including regulators, to accomplish this integration.

Operator Training and Certification

With the myriad of new and changing operational tools, standards, and regulations facing them, system operators must be constantly trained and retrained to perform their jobs. Operator training also is crucial today because there has been a tremendous turnover in personnel due to retirements and experienced operators taking jobs with the newer market participants. Training must be built into operators' schedules and new information must be disseminated rapidly to keep pace with changes in the industry. Control areas and Regions have very active training programs in place. These include individual utility training, on-the-job reviews, new self-help workbooks, computer training programs, and numerous support workshops across North America. NERC also offers videotape tutorials of NERC Policies and Standards.

NERC established its System Operator Certification Program in September 1998 to establish a minimum level of competence required of system operators responsible for reliable operation between operating authorities and the Interconnections. The scope of the certification testing process is limited to basic principles of interconnected systems operations and knowledge of NERC Operating Policies. The Certification Program has exceeded all expectations for acceptance and participation. In its first year, nearly 2,500 operators took the exam, with a 91.7% passing rate. Original expectations were that 800 might test in the first year. NERC's Operating Committee established a requirement for each control area to be continuously manned by at least one NERC Certified System Operator by the year 2000. That goal should easily be attainable.

Operations in an Open Access World

Since its promulgation in 1996, FERC's Open Access Order 888 and its related actions — the pro-forma tariff, related Commission orders, and the future formation of Regional Transmission Organizations — have, and will continue to have, a profound effect on how NERC develops its Operating Standards. This impact is already evident in NERC's development of the transmission loading relief (TLR) procedures for the Eastern Interconnection, which devotes considerable detail to accommodating the obligations of the pro-forma tariff. In fact, the TLR procedure itself has been incorporated into the tariff. This incorporation is a first for any of the NERC Standards or procedures.

NERC and FERC must deal with two issues regarding the interrelationships between the NERC Operating Standards and federal regulation. Both deal with congestion management, but from different perspectives.

Alternatives to Transaction Curtailment for Congestion Management

Each of the three Interconnections has approached congestion management differently. The Western Systems Coordinating Council has used a predetermined matrix of ratings over defined transfer paths. This approach enables system operators to assess how interchange transactions will flow over the transmission system before they begin. Should an overload occur, transmission operators use the WSCC Unscheduled Flow Reduction Procedure to mitigate the constrained facilities.

In ERCOT, congestion management is handled by the ERCOT ISO. The ISO can order transaction curtailments, transmission reconfiguration, and redispatch as necessary to reduce loadings.

The Eastern Interconnection was the last to develop an Interconnection-wide congestion management procedure. And, it has been in the Eastern Interconnection where congestion management has been most difficult to address and has met with the greatest objection from the marketplace.

In 1997, NERC adopted the TLR procedure for the Eastern Interconnection, which uses transaction curtailment as its primary means for reducing the loading on constrained facilities. Because the Eastern Interconnection is electrically more intricate than the Western or ERCOT Interconnections, and with so many more transmission providers and combinations of generation sources and demands, it is not feasible to predetermine transfer paths as in the Western Interconnection. And, unlike ERCOT, no single point in the Interconnection exists where all transactions can be modeled to determine which ones will cause overloads.

Compounding these problems are:

- inconsistencies in determining Available Transfer Capability, which sometimes leads to "oversubscribing" transmission reservations,
- transmission transfer analysis based on "contract" paths in many parts of the Interconnection, rather than actual flow paths, and
- tariff obligations placed on the transmission provider, which limit its ability to provide alternatives to transaction curtailment because of a lack of reimbursement mechanisms.

The NERC Market Interface Committee, along with the Security Committee and Adequacy Committee, has a project under way to address long-term alternatives to using transaction curtailment for congestion management.

Congestion Management Among Regional Transmission Organizations (RTOs)

Many see the development of RTOs and ISOs as a method of "internalizing" the congestion management under the direction of a few wide-area transmission operators. Although that may be true, if these transmission organizations do not use compatible congestion management procedures, then either:

1. Constraint mitigation within the RTO will be more difficult, and possibly unfair to the marketplace, or
2. An RTO will contribute to constraints within other RTOs in the Interconnection.

For example, if RTO "A" uses only local curtailment procedures for mitigating local constraints, then it may be allowing transactions from adjacent RTOs "B" and "C" to continue to contribute to the overload in "A."

If, on the other hand, RTO "A" does not follow Interconnection-wide congestion management procedures to assist in constraints outside its boundaries, then it may contribute to overloads in other RTOs.

The reliability practices among the RTOs within an Interconnection must be integrated. The standards and practices that need this integration include:

- Parallel path flows,
- Transmission loading relief, including the application of different curtailment priorities,
- Ancillary services, and
- Data exchange and sharing between security coordinators.

New Role for Control Areas

For literally decades, NERC Operating Policies have centered on the control area as the basic entity for providing the services that ensure the operating security of the Interconnections. These services include generation-demand balancing, interchange scheduling and accounting, and transmission security. The typical NERC Operating Policy begins with "the control area shall…." Fundamental changes in our industry have resulted in a new way to view the control area concept, and an unexpected interest by generator owners to form new control areas. These changes include:

1. the separation of the transmission and generation sectors,
2. the apparent disparity between inadvertent interchange payback from control areas to their Interconnection and energy imbalance penalties assessed generators, and
3. merchants seeking the greater scheduling flexibility afforded to control areas.

Separation of the Transmission and Generation Sectors

As the generation sector has become restructured and separated from the transmission sector with its open access provisions, in many cases the control area no longer performs many of the functions ascribed to it by the Operating Policies. For example, in most situations, the transmission provider performs the operating security function. Although the transmission provider needs the control area's assistance, the control area may not be the entity responsible for ensuring transmission security. Indeed, the control area may not own generation, and may instead provide for generation-demand balancing through contracts with independent generators.

Inadvertent Interchange Versus Energy Imbalance

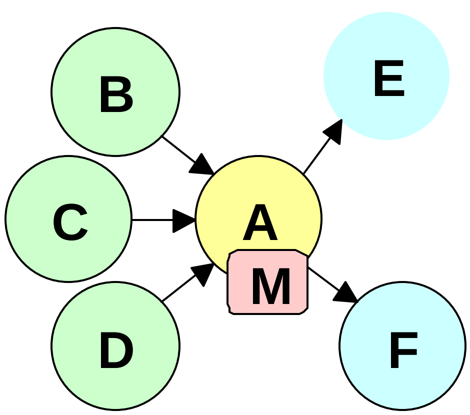
Mismatches between a control area's actual and scheduled interchange may be due to the control area's inaccurate generation control, or to its response to Interconnection frequency errors (when the Interconnection's frequency is above or below 60 Hz). In essence, the first (control problems) creates the second (frequency errors).

Poor control creates an inadvertent interchange between the control area and its Interconnection, and equates to energy either owed to or from the Interconnection. This energy difference is inadvertent interchange. At present, NERC does not specify how much inadvertent a control area may accrue before it must repay. And repayment is with "in-kind" (on- or off-peak) energy, not dollars.

Merchant power producers, however, are generally held to a stricter standard and must pay energy imbalance penalties (dollars) if their generation does not match the schedule they have committed to with their host control area. This different approach may be leading some generators to become control areas, where generation mismatch can be repaid through NERC's inadvertent interchange policies rather than energy imbalance penalties.

Scheduling Flexibility

Control areas also provide the ability to "bank" Interchange Schedules and to provide a "hub" service between a collection of generation sources and customers. In fact, a control area is the only mechanism provided in the Operating Policies that allows Interchange Scheduling.



Consider the diagram on the left. Control area A's affiliate merchant M can schedule interchange from generation in control areas B, C, and D, and sell to customers in control areas E and F. The merchant's control area allows him the flexibility to set up separate purchases and sales by providing a means to bank future interchange transactions and providing a hub to "mix and match" products and customers. In other words, these do not have to be bilateral transactions between the ultimate sources and customers.

The control area's ability to mix and match generation products and customers has not gone unnoticed. The merchant generator in SERC has established itself as three separate generation-only control areas, which gives its marketer the ability to hub generation purchases for a variety of its customers. Other merchant producers have expressed a similar interest in becoming control areas.

The NERC Operating Policies did not envision this use of the control area concept as a marketplace tool. A few years ago, the mergers among the vertically integrated utilities resulted in a decrease in the number of control areas from about 150 to the 138 we have today. A year from now, there may be many more.

To address the rapidly changing role of the control area, the Security Committee established a control area Criteria Task Force. Its charge is to look at all the reliability functions necessary for operational security, and recommend which entities — control areas, transmission operators and providers, generation operators, and so on — provide these functions. This task force is also charged with investigating the needs of the marketplace and recommending new functions and entities to provide these needs. One possibility would be to devise a way to provide the banking and hubbing services to the marketplace without requiring merchant generators to be control areas.

Transmission Issues

Transmission system operators face a number of challenges in maintaining overall system reliability, including the determination of available transfer capability, congestion management, and maintenance of system reactive capability. Additions to the transmission system are hampered by challenges to construction, including a lack of financial incentives to invest in new transmission.

Available Transfer Capability

As the industry has gained experience with Available Transfer Capability (ATC) calculations and their application, a number of inter-related issues have surfaced. These issues include coordination of ATC values calculated by multiple parties and establishment of more standardized industry practices relative to transmission reliability margin (TRM) and capacity benefit margin (CBM).

ATC Coordination

Coordination of ATC is essential to ensure that transmission service requests are satisfied to the greatest extent possible, while avoiding situations where ATCs are "oversubscribed" to the detriment of system reliability. Some Regions have implemented processes to ensure that requests for transmission service that oversubscribe the facilities of others are not approved. A number of transmission providers, however, continue to evaluate only the ability of their own facilities to support the transmission service requests, regardless of the parallel flow impact on other systems. This approach can lead to over-subscription of the overall network's capabilities.

When system overloads occur due to unscheduled flows on system elements caused by network over-subscription, congestion management procedures can be invoked to relieve the overload and preserve the reliability of the network. This approach effectively manages the resultant problems but does not address the root cause, over-subscription of the network.

The coordination of ATC values is particularly difficult to address where "partial path reservations" or "incomplete path reservations" occur. Unless the source and the sink for a transaction both reside within the same host transmission provider, multiple transmission service reservations must be made with a number of transmission providers. The timing, priority, and duration of these multiple reservations make it difficult to coordinate the resultant ATC values among transmission providers and their OASIS postings.

Varying applications of CBM also create a partial path reservation. A load-serving entity purchasing transmission service from an adjoining transmission provider to supply native load does not have to post a transmission reservation on his own system, thereby creating another form of partial path reservation.

Typically, for a transmission customer to purchase a complete source-to-sink path that involves two different but adjacent control areas, two separate transmission reservations must be made. The transmission customer must make a reservation from the source in control area "A" to the interconnection with control area "B," containing the sink. The transmission customer must also make a reservation in control area "B" to the sink from the Interconnection with control area "A." These transmission reservations need not be purchased at the same time. Nor must these reservations be the same "firmness" or duration. Transactions involving more than two control areas or transactions not requiring a reservation on the sink system will further complicate the situation. Such transmission reservations that do not complete a source-to-sink path create ambiguity in the modeling of anticipated system conditions and in coordination (value matching) of the Regionally calculated ATC values. In practice, this issue is further complicated by numerous, similar simultaneous transactions of varying duration and priority that often involve more than two transmission providers.

NERC's Available Transfer Capability Working Group (ATCWG) has defined some current problems in its recent report to encourage further discussion and work toward resolution of these issues.

- How is a "partial path" reservation made with one provider considered in the ATC determination process of another impacted provider?
- Does inclusion of a "partial path" reservation in interregional ATC coordination implicitly make a reservation on adjacent series path provider(s), i.e., the system on which the reservation has yet to be made? If so, how do the transmission providers know how to account for new transmission service requests that will be used in conjunction with other reservations made with other transmission providers to prevent double counting? Currently, a completed contract path effectively makes a "reservation" on all parallel paths.
- Should reservations be tagged and associated with other reservations that must be used together to complete a source-to-sink path?
- Should transmission customers be required to make all reservations necessary to complete a source-to-sink path at the same time?

Some progress has been made in coordinating ATCs, particularly where a centralized approach is used, such as the MAIN Region. In other cases, decentralized coordination methods, such as that used by ECAR and several of its neighbors, are being implemented. However, more work is required to perfect these coordination procedures.

The ATCWG is working with the Market Interface Committee and the security coordinator Subcommittee to address the "partial path" issue and ATC coordination, in general. ATCWG wants to be assured that the interests of both the market and those responsible for the reliability of the transmission system are balanced in determining solutions to these problems.

TRM and CBM

Current industry practices regarding TRM and CBM vary considerably from Region to Region and from one transmission provider to another. This often exacerbates inconsistencies in posted ATC values and confusion among industry participants.

NERC's ATCWG has been working to resolve inconsistencies in the determination and application of TRM and CBM and has proposed draft NERC Planning Standards to address both of these transmission transfer capability margins. The draft standards were presented to the NERC Adequacy Committee at its July 1999 meeting and were remanded to the ATCWG and the Planning Standards Subcommittee for review. As proposed, the draft standards require standard Regional methodologies for the calculation of both TRM and CBM. The proposed standards are going through the Process for Developing and Approving NERC Standards.

Additionally, in July 1999, FERC issued an order requiring all transmission providers to disclose the methods used to determine CBM as well as the actual CBM values. The order also required that NERC work with transmission providers to establish a standard CBM methodology by the end of 1999. NERC has responded to FERC that it believes that standard methods for the determination of CBM can be developed by each Region by the end of 1999. Regional methodologies have been developed by each Region and will be implemented in 2000.

Maintaining System Reactive Capability

A significant challenge to the transmission providers will be to maintain adequate levels of reactive support for the transmission system in the new open-market era. Unlike the real power (MW), the reactive component of power (MVAr) cannot be easily transmitted over distances and must be supplied locally. Reactive power is supplied by: generators, synchronous condensers, shunt capacitors, and very specialized reactive support devices generally known as static var compenstors (SVCs). Without adequate reactive support, parts of the system can be susceptible to potential voltage collapse or instability.

During the heat waves of 1988, severe voltage depression was experienced in the area surrounding the southern end of Lake Michigan due to a high demand for air conditioning, coupled with a number of localized generation outages. Most air conditioner demand is motor load, often with a poor power factor, requiring significant reactive power to operate. Because a number of generators in that area were not operating, they were unable to supply the needed reactive power. Following that incident, many utilities in the Midwest made concerted efforts to improve reactive support by adding shunt capacitors on their distribution and subtransmission systems. Such reactive support programs must be ongoing as demand on the distribution system continues to grow, and a chief component of that growth, air conditioning, requires it. However, there may have been a falloff in recent years in maintaining such distribution reactive improvement programs. Because of its interaction with the transmission system, reactive support is one area that distribution companies cannot ignore if reliability is to be maintained on the bulk transmission system.

Voltage problems experienced in MAAC, SERC, and ECAR during the 1999 summer highlight another important aspect of system reactive requirement — reactive support for transmission transfers. The physics of transferring power across a transmission line causes it to consume reactive power, and although it may not be thermally overloaded, the voltage drop across the line increases significantly. When heavy power transfers occur across a transmission system interface and transmission lines are heavily loaded, voltage in the area of the interface can become depressed if sufficient reactive supplies are not available to the system.

When transfers of power follow a consistent directional pattern, it is relatively easy to plan and cost justify the required reactive support for the transfers. Significant reactive support was added on the bulk system to enable higher transfers from ECAR to MAAC and the VACAR Subregion of SERC in the early 1990s. However, under open access, transactions are being done in large numbers across long distances, and often in directions that were not anticipated when the transmission system was planned and built. Also, the direction and amount of transfers has become much more volatile, changing daily and, sometimes, hourly. Consequently, planning reactive support enhancements for improving transfer capability is now extremely difficult.

There is currently no incentive to increase the levels of reactive support on the bulk power systems. In fact, there are disincentives. Generators are paid to produce MW, not MVAr. Since reactive power generation capability drops off as the MW output of a generator is increased, there is always a tradeoff. A recent spate of nuclear unit upgrades effectively lowered the units' reactive power output capabilities.

Any reactive support enhancement must be extremely versatile to accommodate rapidly changing system conditions and power transfers. Throughout, care must also be taken to be mindful of the dynamic reactive requirements of the system — the instantaneously responsive type supplied by generators, synchronous condensers, and SVCs. Also, planners and operators must work together to determine the future needs for dynamic reactive support. As mentioned earlier, care must be taken to replace reactive support in kind from those critical generators as they are retired. Recently, when the Zion nuclear units were retired, their generators were converted into synchronous condensers, providing much needed dynamic reactive power for voltage support in that part of the system.

Near real-time voltage collapse analysis is now being done on an even-wider scale by security coordinators, ISOs, and transmission providers. In the past, such analysis was only possible in the planning arena. Advances in programs and computer technology have brought this important tool into the operations area. Feedback from the operating area to the planners on observed reactive requirements is most helpful in planning future system reactive enhancements.

Congestion Management

As the transmission system is more heavily used for open access transactions, one of the ongoing issues will be the need for congestion management. When system operators are faced with transmission overloads due to unscheduled flows on system elements, they must take action to relieve the overload and preserve the reliability of the network.

Since the inception of interconnected system operation, control areas have cut schedules on the overloaded paths or redispatched their generation to relieve the overloads. Only occasionally did scheduled transfers on adjacent systems cause significant parallel flows that could not be mitigated by these corrective actions. The cost of the redispatch was an acceptable offset to the benefits of interconnected operations.

As large, long-distance, multiparty transactions became commonplace, so too did an increase in parallel path flows and spurious overloads that could not be easily explained or relieved. To help identify which transactions were causing the overloads, NERC initiated transaction “tagging” in 1997, and the development of an Interchange Distribution Calculator. At the same time, the security coordinators were empowered to initiate TLR procedures, which remain the most prevalent congestion management method today. As the system has become more heavily loaded over the last two years, the incidents of TLR have seemingly become commonplace occurrences.

Transmission service is being sold and transactions are being scheduled without regard to the impacts of those schedules on the entire network. As a result, the capabilities of the network are being oversubscribed. Instead of managing the transmission system before the fact through wide-area calculation and coordination of ATCs, the security coordinators end up managing the resultant problems and not the root cause.

Part of the need for TLR as a congestion management technique is the fact that the current contract path scheduling procedures do not agree with the laws of physics governing electricity flow on the system. New scheduling methods are needed that can better bridge the difference between the way the market views the system and the underlying physical system behavior and limitations.

Other potential congestion management methods include redispatch of generation, either directed by the control area operators or security coordinators, or market driven through contractual arrangements made by the market participants. At its May 1999 meeting, NERC’s Board of Trustees charged the Market Interface Committee to lead the effort of developing long-term solutions to congestion management. That effort is currently under way. As part of that effort, NERC sponsored a market redispatch (MRD) experiment beginning in the summer of 1999. So far, only a handful of redispatch arrangements have been set up, but none have been executed. The Board has extended the MRD experiment for the summer of 2000. Additional improvements and tools are being added, including use of electronic tagging (E-Tag) and interfacing with the Interchange Distribution Calculator to predetermine the effectiveness of the proposed redispatch. The security coordinator Subcommittee is also refining NERC’s TLR procedures to enhance their effectiveness and address concerns raised by FERC.

Whatever long-term strategy is adopted for congestion management, it should include feedback on congestion to enable appropriate planning of transmission and generation solutions to provide lasting system improvements. The techniques should also financially encourage the implementation of those improvements.

Generation and Transmission Planning Coordination

This past year has seen a significant increase in merchant plant activity in some of the Regions. Current high interest in interconnecting to the transmission system has resulted in study times of up to two years before a merchant owner can determine the transmission infrastructure costs required for the merchant plant. Often, interconnection study requests are made for several sites for a single developer to analyze for a single proposed plant.

One difficult problem facing transmission owners is determining which merchant plant(s) will be built and which ones to represent in concurrent studies. For example, if interconnection requests are made to the transmission provider for four closely located merchant plants, the interconnection requirements for each plant will be different for varying combinations of the proposed projects or if only a single plant were to be constructed. Multiple simultaneous interconnections may require more transmission infrastructures to be built, some of which will be built and operated at extra-high voltage (EHV), requiring more planning and construction time than for lower voltage system additions. This time lag may lead to some output curtailment for some of the new plants until the necessary transmission additions can be built to support them.

Planning for the connection of multiple merchant plants also poses another coordination problem for wide-area transmission planning. Although merchant plant connection requests are typically directed to the local host transmission provider, the new plant can often have impacts on neighboring systems. It is incumbent on the host transmission provider to ensure proper coordination with its interconnected neighbors. Confidentiality agreements between proposed merchant plants and the host transmission system make Regional and interregional coordination even more difficult. By the time merchant generation plans can be openly discussed and analyzed in current coordination forums, plans for transmission system enhancements may have already been finalized with the merchant, without the essential planning coordination with neighboring systems. Just as in the determination of ATCs, it is imperative that the transmission system be planned in a coordinated fashion on a wide-area basis to ensure reliability and system stability.

The market is providing some creative solutions to deal with some plant interconnection issues. For example, one merchant plant is being built where all four units can be switched between the ERCOT Interconnection and the Eastern Interconnection. Other merchant plant owners are considering similar connections. Similar switchable plants have existed for years on the WSCC-MAPP border. Other merchant plants in the Eastern Interconnection are being built at the electrical boundaries of power pools or major transmission systems, enabling the merchants to take advantage of price differentials between the two systems. These plants create a different set of problems, including how to account for the generating capacity in analyzing resource adequacy of each Region or Interconnection, and how to analyze the transmission impacts created by or voltage system support afforded by the new plants.

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. If projected capacity resources are placed in service and generation availability is maintained at or above levels experienced in recent years, the capacity resources will satisfy the Region's criterion for reliability adequacy during the 1999–2008 period. There remains particular concern on the certification difficulties of American Electric Power's Wyoming-Cloverdale 765 kV line, which is needed to guard against the potential for widespread interruptions.

As the industry moves toward increased competition, ECAR's membership is striving to meet the challenge of maintaining the adequacy and security of the bulk electric systems. ECAR continues to review and update its organizational structure, governance provisions, reliability assessment process, and technical documents and guides to ensure that reliability is maintained in the changing environment and that ECAR is in compliance with NERC Policies and Standards. Full ECAR membership has been opened to its associate members. The ECAR members also continue to enhance their Open Access Same-time Information System (OASIS) to improve its maintainability and availability.

ECAR Assessment Process

In ECAR, planning for facility additions is done by individual member utilities. Regional reliability assessments are performed to ensure that members' plans are well coordinated so that Regional reliability criteria are met. Assessments are performed by the ECAR Generation Resources Panel and Transmission System Performance Panel under direction of the Coordination Review Committee. ECAR assessment procedures are applied to all generation and transmission facilities that significantly affect 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 ten-year or longer planning horizon, and semiannual seasonal assessments are made for the upcoming peak demand seasons. Transmission assessments are performed regularly for selected future years out to the planning horizon and semiannually for the near term. If deficiencies are discovered during this process, the member system with the deficiency is asked to explain what remedial action will be taken. The assessment procedures for both transmission and generation resources were recently modified to continue their relevance in today's competitive environment.

Demand and Energy

Throughout the assessment period, the total internal peak demand of ECAR members is expected to continue to occur during the summer, increasing to about 110,900 MW by 2008, a 1.7% equivalent compound growth rate, which is about the same as last year. ECAR continues to review demand-reporting issues to ensure meaningful reliability assessments in the open access environment. Current resource plans developed by ECAR members project a reliance on direct controlled and interruptible load management programs of about 3,400 MW by 2008 and plans also include 300 MW of new demand-side management programs. With interruptible loads and loads under demand-side management removed, ECAR's net internal demand is projected to grow to about 107,500 MW in 2008.

For the second year, ECAR has conducted a supplemental assessment to capture load due to customer choice and that is no longer being included in traditional reporting processes. A survey of ECAR members identified about 3,000–3,900 MW of additional, unreported demand.

Resource Assessment

ECAR members develop ten-year capacity plans that reflect the new capacity necessary to reliably serve demand and energy in the Region. ECAR members' capacity "plans" are not necessarily commitments to construct capacity, but statements of the capacity the market needs to provide to reliably serve forecast demand. These plans project the addition or contracting for about 9,900 MW of new capacity. About 1,500 MW of the projected generation additions is reported to be under construction or under contract. Of the remaining "planned" new capacity, about 6,800 MW is projected to be short lead-time combustion turbines, with most of the new capacity projected to be gas-fired. "Planned" capacity, as reported by ECAR members, is likely to be provided only in response to market conditions. For example, two-thirds of the capacity currently under construction was not reported in last year's planned capacity additions.

Capacity margins during the 1999–2003 period are projected to reach a low of 7.4% in 2002, based on total internal demand, and reaches a ten-year low of 1.8% in 2008. If capacity reported as planned is excluded, capacity margins will become negative in 2006.

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. One of the most critical parameters affecting the adequacy of bulk electric supply in ECAR is generation availability. The 1999 capacity margin assessment determined that the annual generation availability must remain at or above 80.3% to meet the DSCR criterion throughout the 1999–2003 period. For perspective, average annual generation availability in ECAR has been 81.6% over the last ten years and was 82% during 1998.

ECAR believes that the aging of generating capacity will necessitate increased maintenance and lengthened outages. By the year 2008, about 67% of the capacity in ECAR will be 30 or more years old and about 27% will be 40 or more years old. ECAR members recognize the challenges in maintaining high levels of generation availability experienced in recent years but expects to meet them. As margins continue to decline, coordination of maintenance schedules will become more important and difficult.

Coal, the predominant fuel used within the ECAR Region, is expected to supply about 72% of the total generating capacity in the year 2008. In order to comply with recently approved NO_x regulations, ECAR members may have to install a significant number of SCR NO_x control units. During installation of this equipment, unit availability will be further decreased at a time when capacity margins are declining. Litigation regarding these NO_x regulations makes it even more uncertain as to when companies will commit to install this equipment, and whether the Environmental Protection Agency will change the existing May 2003 compliance date. The impact on the reliability of the ECAR Region is being studied separately by ECAR and NERC and has not been factored into this self assessment.

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 planning to install phase angle regulators (PAR) in the remaining uncontrolled interconnections between the Detroit Edison and Ontario systems by summer 2000. With the PAR additions, the inadvertent circulation around Lake Erie that has often limited the ability of the Michigan systems to receive firm purchases from Ontario can be controlled to improve the transfer capability between ECAR and NPCC (Ontario). The impact of the PAR installations is under study by the interregional study groups.

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 460 miles of extra-high voltage (EHV) transmission lines (230 kV and above) that are expected to enhance and strengthen the bulk transmission network. Included in these planned additions is the American Electric Power (AEP) Wyoming-to-Cloverdale 765 kV transmission project.

This project, originally scheduled for service in May 1998, has encountered certification difficulties, although some progress has been made during the past year. In May 1999, AEP filed information on an alternative 765 kV line from the Wyoming Station to the Jacksons Ferry Station, as requested by the Virginia State Corporation Commission hearing examiner. Public hearings on this alternative were held this summer, and evidentiary hearings will be held later this year to consider both the original Wyoming-Cloverdale 765 kV Project and the Wyoming-Jacksons Ferry 765 kV Alternative Project. The earliest date either of these projects can be completed is June 2004, increasing the potential for widespread interruptions in southeastern ECAR. A tri-regional assessment of the reliability impacts of this project concluded that a reliability risk exists due to the delay of this project. Although operating procedures can minimize the risk of widespread interruptions, the likelihood of such power outages will increase until the project can be completed.

Operations Assessment

Three security coordinators maintain reliability of the transmission system in the ECAR Region by monitoring and controlling critical transmission interface loading. American Electric Power is the security coordinator that monitors power flows in the southern, central, and western subregions of ECAR. Allegheny Power is the security coordinator that monitors power flows in the eastern subregion of ECAR. The Michigan Electric Coordinated Systems is the security coordinator that monitors power flows in the northern subregion of ECAR. 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, other significant operating procedures are available to maintain reliable system operations. These include:

- The Reliability Coordination Plan 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.
- Recently, several ECAR members entered into a multiregional agreement (Lake Erie Emergency Re-dispatch Procedure) involving control areas located around Lake Erie to use generation redispatch to minimize the need for applying emergency TLR procedures and curtailments that would require the affected system(s) to curtail firm load.
- The AEP security coordinator will employ a series of operating procedures to control power flows on AEP’s Kanawha River-Matt Funk 345 kV circuit to reduce the reliability risks of potential widespread interruptions in southeastern ECAR and surrounding areas.

The East Central Area Reliability Coordination Agreement (ECAR) membership currently consists of 16 full members and 35 associate members serving either all or parts of the states of Michigan, Indiana, Kentucky, Ohio, Virginia, West Virginia, Pennsylvania, Maryland, and Tennessee.

ERCOT

The near-term generation resources requirements can be met from the existing reserves of generation capacity of the utilities and qualified facility cogeneration plants. In addition, new generation capacity planned or under construction will add approximately 1,670 MW in 1999. Beyond the year 2000, many new proposals for generation resources have been made and, if built, will maintain planning reserves at a reliable level. The new resources are gas-fired, high-efficiency gas turbine combined cycle plants.

The transmission system required to move energy from the generation location to the load centers is adequate for the near term. In 1999, during high load periods, a number of transmission constraints may be experienced, and Transmission Load Relief procedures may need to be invoked. The constraints will continue to limit some of the transfers until new transmission projects are completed. Future transmission required for interconnection of new generation resources will be reliable only if sufficient time exists to acquire 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.

ERCOT Assessment Process

The Engineering Subcommittee produces and performs the power flows required for the members to assess the reliability of their transmission systems. An annual report 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. The study work done by the subcommittee is not intended to be an exhaustive study of all the contingencies that would be necessary to test the system and prove the reliability criteria. Rather, it is the responsibility of each member to test their systems, and report to the subcommittee those issues that might pose a future reliability concern.

The subcommittee is very involved with the conversion of the existing guides and criteria to be consistent with the NERC Planning Standards and Guides as well as implementation of the Compliance Template Pilot Project.

Demand and Energy

The actual 1998 ERCOT summer demand grew to 53,689 MW from 50,150 MW, a 7.1% increase. This demand includes serving interruptible loads. For the 1990–1998 period, the average annual compound growth rate has been 3.2%.

The actual ERCOT energy consumption grew from 249,169 GWh to 267,970 GWh, a 7.5% increase. For the 1990–1998 period, the compound annual growth rate was 3.2%.

The average annual growth rate in ERCOT's summer peak demand is projected to be 2.4% for the 1999–2009 period and the expected winter peak demand is projected to grow at 2.4%. The projected annual growth for energy is 2.3%.

ERCOT is within its 15% reserve margin when interruptible loads are removed. Peak demands, however, appear to be increasing above the currently projected annual growth rate of 2.2%, indicating that ERCOT's reserve margin will fall below 15%.

Resource Assessment

Loss-of-load-probability (LOLP) and loss-of load-hours (LOLH) reliability studies were not made in 1998. The ability to continue making these types of calculations in the future may be compromised by the lack of data concerning performance and forced outage rates and the inability to identify future generating unit additions.

The future resources that have been specified in the Capacity-Demand-Reserve Working Papers as unspecified have brought many new proposals for new generation sources and interconnections. Since January 1, 1998, over 20,000 MW of new capacity have been proposed for construction in the 1999–2002 time frame. While it is unlikely that all of the proposed generation will be built, the forecast for new generation continues to improve. An estimated 1,670 MW of generation will be completed in 1999.

ERCOT should continue to have adequate resource reliability as long as the entities responsible for securing capacity resources allow sufficient lead time in their acquisition process to ensure the capacity and associated transmission support is available when required.

Transmission Assessment

The transmission system is experiencing constraints during high load periods. The expected 1999 transmission line loadings for transfers from South-to-North ERCOT have increased to the point that ERCOT has developed Transmission Line Loading Relief procedures. For long-term transmission planning, ERCOT has approved new transmission lines to be constructed to address these constraints and strengthen the bulk transmission system to accommodate new generation and increased loads. The timing of these new facilities will be important to reliability. ERCOT is currently experiencing much higher-than-anticipated load growth. New generation is needed and is being proposed by the generation entities; however, timing again is critical. The ERCOT Independent System Operator (ISO) continues to monitor planned transmission service and generation interconnection requests to determine reserve levels.

Operations Assessment

The ERCOT-ISO that went into operation in January 1997 continues to schedule and approve all transactions and make daily assessments of transfer capability and security based on load flow simulations of the system that include expected outage conditions.

The Electric Reliability Council of Texas (ERCOT) is comprised of six municipal G & Ts, seven cooperative G & Ts and river authorities, four investor-owned utilities, nine independent power producers, 39 power marketers, 14 transmission-dependent utilities, one power broker, and one associate of ERCOT. ERCOT members serve over 12 million customers (and about 200,000 square miles or 73% of Texas) and account for 56,000 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 Regional reference reserve margins throughout the 1999-2008 assessment period.

FRCC was created in October 1996 to ensure bulk electric system reliability in Florida. FRCC members regularly exchange information related to the reliability of the bulk electric system in both planning and operating areas. 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. The Reliability Assessment Group (RAG) administers this process and determines what planning and operating studies will be performed during the year to address those issues.

RAG is also the mechanism for collecting, assembling, and assessing the Regional EIA-411 Report, and the FRCC Load and Resource Plan, which is submitted annually to the Florida Public Service Commission.

Assessment Process

Within the FRCC Region, the 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 load flow, stability, and short-circuit databases for the use of FRCC and its members.

Annually, RAG reviews existing and expected conditions within the Region both short and long term. RAG, which includes planning, marketing, and operating members, makes recommendations to the 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 that include results, conclusions, and recommendations are published. RAG monitors actions taken to meet reliability criteria as a result of all study report recommendations.

The FRCC has also developed a Compliance Review Program to ensure member and Regional compliance with FRCC and NERC Planning Standards.

Demand and Energy

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 the energy growth rates for Florida for the next ten years are 2.3 and 2.2%, respectively. These forecasted growth rates are lower than the ten-year historical average growth rate of 3.5 and 3.3% due to changes in the University of Florida projections of population growth. These indicate a moderation in population growth in the FRCC Region over the assessment period versus the previous ten years.

Resource Assessment

The reserve margins for the ten-year assessment period (1999–2008) are at or above the FRCC reference reserve margin criteria of 15%. The Resource Working Group, as part of its overall assessment of resource adequacy, determines reserve margin 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 loads during the peak demand periods. FRCC members are projecting the net addition (i.e., additions less removals) of over 9,658 MW of new capacity over the next ten years. Of this, more than 9,931 MW are projected to be natural gas-fired combined cycle units and approximately 1,800 MW is currently committed.

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 a dynamic marketplace in today's changing and competitive environment. This changing environment will continue to place more emphasis on increased efficiency of existing units.

Due to an incident in 1998 affecting the Florida Gas Transmission Company's (FGT) gas pipeline into Florida, the FRCC worked with the FGT to address concerns expressed by the Florida Public Service Commission over the reliability of the natural gas supply into the state. FGT presented measures designed to prevent reoccurrence of that type of event, including various looping features of the existing facilities, contingency plans, and various other measures to improve or maintain the reliability of supply. With respect to gas supply for new projects, proposals have been made to either expand the FGT system or to add new pipeline capacity into the state. One major generation project has already committed to FGT and expansion permitting has begun.

Project proposals decide on the choice and availability of backup fuel based on their individual circumstances.

Transmission Assessment

The FRCC Stability Working Group (SWG) completed studies of outage performance for the years 1999 and 2005 based on expected power import from the Southern Subregion of SERC to the FRCC. The SWG found no problems for 1999 summer and winter peak load scenarios. In the long term, any potential problem areas will continue to be monitored as generation plans solidify, and there is adequate time to resolve any potential problems in a timely manner.

In the past, the SWG studies had identified a Central Florida/South Florida swing mode that was poorly damped for certain 230 kV and 500 kV circuit outages. The installation of power system stabilizers at key plants in 1998 has improved damping of this swing mode to an acceptable degree in the near term. In the long term, some of the new units might require power system stabilizers.

The FRCC Transmission Working Group (TWG) completed a ten-year, intraregional study that comprehensively evaluated the FRCC transmission system under normal and outage conditions for the years 2000, 2001, 2002, and 2005 based on the expected power import from the Southern Subregion of SERC to the FRCC. The results of this study indicate that any thermal or voltage violations can be successfully managed in the short term by operator intervention including generation redispatch, sectionalizing, reactive device control, and transformer tap adjustments. In the long term, violations of criteria can be resolved by planned transmission projects or there is adequate time to monitor trends and construct required network upgrades. Individual members plan to construct 391 miles of 230 kV and 36 miles of 500 kV transmission during the 1999–2008 assessment period.

The Florida/Southern Planning Task Force performs interregional transmission studies as required to evaluate the transfer capability between the Southern Subregion of SERC and the FRCC.

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 that gives the security coordinator the authority to direct actions to ensure the real-time 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 operating members on an as-needed basis throughout the day. The procedures in the security process are being evaluated and updated on an ongoing basis to ensure Regional reliability, conformance to FRCC procedures, and adherence to NERC Standards and Policies.

The Florida Reliability Coordinating Council (FRCC) membership includes 34 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

The MAAC bulk power system as planned through the 2003/04 planning period meets the MAAC Installed Generating Capacity Requirements. This represents a substantial improvement compared to last year's assessment and can be attributed to approximately 5,000 MW of publicly announced capacity additions planned to be in service by 2004.

The MAAC bulk power system as planned for the 2000/2001 planning period meets the Single Contingency requirements of the MAAC Criteria for the tested conditions. During summer peak load conditions, insufficient transmission capability in south central Pennsylvania can result in voltage-related stresses on local transmission and subtransmission systems. Short-term operating procedures are in place to prevent any interruption of local load and a long-term solution to the problem will be identified through the PJM Regional Transmission Expansion Planning Process.

Maintaining Reliability in the Changing Environment

As the industry moves rapidly toward retail customer choice, the Mid-Atlantic Area Council (MAAC) is addressing the challenge of maintaining the adequacy and security of the bulk power electric systems. With wholesale open access, some Regional load is supplied under contracts that have no commitments beyond the contract duration. It is likely that under retail access there will be a dramatic increase in the number of these capacity contracts and a decrease in the duration of these contracts. For example, at the beginning of 2000, retail customer choice will be available to all customers in Pennsylvania. Similar regulations have been passed in New Jersey, Delaware, and Maryland. The future challenge will be to develop a process to provide adequate capacity resources recognizing that a large amount of load can switch suppliers on a billing cycle basis. MAAC continues reviewing its organizational structure, governance provisions, reliability assessment process, and technical documents and guides to ensure that reliability will be maintained in the changing environment, and that MAAC will be in full compliance with the NERC Planning Standards and Operating Policies.

MAAC Assessment Process

Transmission assessments are performed regularly for selected future years out to the planning horizon, and semiannually for the near-term system. If deficiencies are discovered during this process, the member with the deficiency is required to explain what remedial action will be taken. Each year the necessary reserves to remain at a loss of load probability of one day in ten years are calculated for the ten-year planning horizon. An agreed to reserve requirement is then set for the planning period two years in 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 study groups.

PJM has established a Regional Transmission Expansion Process that will be utilized to enhance the MAAC bulk power system if MAAC Reliability Assessments or NERC Standards compliance deem system expansion necessary.

Demand and Energy

Net peak demand and energy forecasts for 1999 are increased compared to the 1998 forecasts because of anticipated strong economic growth. The net peak demand growth rate grows again to 1.6% from last year's 1.4%. Company growth rates vary from 0.5 to 2.7%. The energy growth rate also grows to 1.6 from 1.5%.

Installed Generating Capacity Requirements

The MAAC bulk power system as planned through the 2003/04 planning period meets the MAAC Installed Generating Capacity Requirements. This represents a substantial improvement compared to last year's assessment and can be attributed to approximately 5,000 MW of publicly announced capacity additions planned to be in service by 2004. In addition, 16,000 MW of capacity additions that have not been publicly announced are also planned to be in service by 2004. It must be noted that some of this capacity is speculative and may never be built. The degree to which the requirements of this standard are met in future assessments will ultimately depend on how much of this planned capacity is actually installed.

All subsystems meet the loss of load probability of no more than one day in ten years, on average; however, future deliverability margins are tight for some subsystems.

There are two additional issues that could have a significant impact on generation adequacy. The first is that price disparities between Regions may induce MAAC resource owners to commit their firm capacity to parties outside of MAAC. The second issue concerns the impact of retail competition on active load management. Both of these issues are the subjects of considerable discussion within the PJM committee structure.

Transmission Adequacy and Security Requirements

The MAAC bulk power system as planned for the 2000/2001 planning period meets the Single Contingency requirements of the MAAC Criteria for the tested conditions, with the following exception:

- Insufficient transmission capability in the Lancaster, Pennsylvania area can result in voltage-related stresses on local transmission and subtransmission systems during summer peak load conditions for the loss of the Brunner Island–South Manheim 230 kV line and South Manheim 230/69 kV transformer. Short-term operating procedures are in place to prevent any interruption of local load. A long-term solution to the problem will be identified through the PJM Regional Transmission Expansion Planning Process.

The MAAC bulk power system, as planned for the 2000/01 planning period, meets the Second Contingency and Double Contingencies requirement of the MAAC Criteria for the tested conditions.

The MAAC bulk power system meets the Stability Requirements of the MAAC Criteria for the tested conditions. Some of the slowly damped MW flow oscillations seen in the results of the 1997 Assessment for contingencies in western Pennsylvania can be attributed to modeled low MVAr output at Keystone Station. Other oscillations that are seen for various contingencies throughout MAAC are related to the approximate 0.7 Hz oscillations seen throughout the northern part of the Eastern Interconnection. These slow modal oscillations manifest themselves as MW and MVAr swings on lines that run between the groups of oscillating units. Units in western MAAC are in one group with units in western New York and Ontario and units in eastern and southern MAAC are in the other group with units in eastern New York and New England.

Abnormal Disturbances Testing

The MAAC bulk power system, as planned for the 2000/2001 planning period, was tested for the Abnormal Disturbances requirements of the MAAC Criteria. This requirement is prescribed as a practical means to study the system for its ability to withstand disturbances beyond those that can be reasonably expected, some of which are quite severe, and is used to assess system strength and uncover areas of potential system vulnerability. A subset of all possible contingencies that captures the impact of many, but not all, of the contingencies affecting the 230, 345, and 500 kV facilities was tested. Future studies will analyze more of these contingencies.

Several of the tested contingencies resulted in depressed system voltages and severe overloads that could jeopardize the integrity of the bulk system. Some of the identified problems are aggravated by specific system conditions such as high regional or interregional power transfers. Others are caused by more local stresses such as high local area imports or exports.

Relaying and Protective Devices

The performance of relaying and protective devices on the MAAC bulk power system was evaluated by reviewing pertinent PJM reports. A small increasing trend in non-fault operations caused by defective 500 kV circuit breakers was identified. When coupled with increased circuit breaker problems associated with multiple facility trips at transmission voltage levels, the performance of circuit breakers may be a concern. MAAC staff will closely monitor trends in this category of non-fault operations and multiple facility trips involving circuit breaker malfunctions.

Network Transfer Capability

The ability of the MAAC bulk power system to transfer power from one area to another during normal and emergency conditions is adequate as planned for the 2000/01 planning period for the tested conditions with the following items noted:

- The Eastern Region now meets its deliverability objective with a small margin. Although scheduled capacity additions should improve deliverability, the Region will require monitoring until its margin improves. Future margins will ultimately depend on how many of the projects are actually completed.

- The Delmarva Peninsula Subarea meets its deliverability objective for the planning period with no margin. Although a number of scheduled, minor transmission upgrades should improve deliverability, the subarea will continue to require monitoring.

- The east central New Jersey Subarea meets its deliverability objective for the planning period with a small margin. The extent of transmission reinforcements necessary for the subarea to meet its deliverability obligation for future planning periods depends on the ultimate outcome of the retirement status of Oyster Creek Station.

The Mid-Atlantic Area Council (MAAC) 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 load. There are 15 full and 30 associate members of MAAC.

MAIN

Although the unusual outage of several nuclear generating units caused an increased risk to reliability in 1998, MAIN expects to have adequate generating capacity and transmission import capability to meet its reliability criteria throughout the 1999–2008 period.

Demand and Energy

Summer peak demand for the 1999–2008 period is forecast to increase at an average annual rate of about 1.5%, about the same as last year's projected rate. The actual Mid-America Interconnected Network (MAIN) 1998 demand of 46,824 MW was about 0.6% lower than last year's forecast.

The projected average annual growth rate of electrical energy for 1999–2008 is 1.4%, slightly below last year's forecast rate. Actual energy use in MAIN in 1998 was 244,073 GWh, which was slightly lower than the 1998 forecast.

Resource Assessment

More than 8,000 MW of net production capacity resources are expected to be added within the MAIN Region during the next ten years. As a result of deregulation in Illinois, a significant portion of the new generation capacity is expected to be provided by nonutility generation. Long-term reserve margins (years 2001 through 2008) for MAIN as a whole are projected to remain near the minimum of the recommended range of 17 to 20% (14.5 to 15.7% capacity margin). In the short term (years 1999 and 2000), reserve margins are projected to remain above 15%. The majority of planned capacity additions in MAIN are short lead-time combustion turbine peaking units.

Supply adequacy in MAIN is assessed using loss of load expectation (LOLE) analysis. This methodology accounts for load forecast uncertainty due to all factors, including weather and diversity among NERC Regions. 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 LOLP) throughout the entire study period, based on the projected yearly reserve margins for MAIN and an assumed adequate import capability.

Transmission Assessment

For the summer of 1999, MAIN has judged that interregional non-simultaneous import transfer capability from MAPP and SPP to be adequate, and from ECAR and TVA marginally adequate. In general, MAIN import capabilities from surrounding Regions increased or remained the same in the alternate scenarios studied for 1999 summer. Details of the MAIN assessment are contained in the NERC *1999 Summer Assessment* report.

MAIN's Future System Study Group long-term analysis of MAIN interregional non-simultaneous import transfer capability indicates that the overall MAIN transmission system should be adequate to support reliable operations.

In addition to MAIN's Future System Study Group, two new long-term study groups have been formed. One group is studying the south central Illinois area and the other is studying the Wisconsin-Upper Michigan area of MAIN. Both groups are concentrating on developing transmission solutions for higher import capability. The Wisconsin group includes representatives from the adjacent MAPP companies as well as from the MAPP Regional staff. This group is studying transmission system improvements in MAPP, northern Illinois, as well as Wisconsin. The Illinois group also is specifically investigating export capability out of or across central Illinois.

Three new transmission lines are planned for the MAIN Region in the near future, and Ameren's new Sioux-Roxford 345 kV line was placed in service this summer. ComEd has obtained certification for two additional 345 kV lines from Lockport to Lombard that have an anticipated service date of summer 2001. Wisconsin Public Service Corporation and Minnesota Power have announced plans to construct a 250-mile, 345 kV line from Wausau, Wisconsin, to Duluth, Minnesota. Depending on siting and regulatory outcomes, the line could be in service by 2002.

Operations Assessment

The MAIN Coordination Center (MCC) in Lombard, Illinois, is the regional security center as well as the OASIS node. (The MCC provides OASIS service to MAIN members as well as Entergy, TVA, and Associated Electric Cooperative.) The MCC performs ATC studies for its members on a daily basis and uses the NERC SDX (system data exchange) to more accurately model adjacent systems. The MCC is a 24-hour office serving security and ATC functions around the clock.

The summer of 1998 presented several operational challenges to the MAIN center. On June 25, 1998, MAIN as a Region was unable to maintain its necessary operating reserves and called for all of its members to curtail their interruptible customers. During peak demand months, MAIN conducts a morning conference call in order to coordinate operations for the upcoming day. Adjacent Councils, their members, and regulatory bodies also participate. The conference call on the morning of June 25, 1998 alerted the MAIN companies to the likelihood of inadequate reserves by the middle of the day.

Throughout the summer of 1998, the MCC dealt with numerous transmission loading relief requests. MAIN uses the NERC transmission loading relief (TLR) procedure as its primary line loading relief tool.

The MAIN Regional Security Application Network is nearing completion. This system supports a 15,000-bus state estimator model with high-speed contingency checking.

To enable its members to meet the requirements of the NERC DCS, MAIN is a reserve-sharing group with an automated callable reserve system that is tested on a weekly basis.

In the spring of 1999, each MAIN member who served native load 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 load.

MAIN Assessment Process

MAIN's individual member utilities plan their own facility additions. MAIN performs Regional assessments, under the direction of the MAIN Engineering Committee (EC), to ensure that members' plans are coordinated to provide a reliable system. The EC's Transmission Task Force performs short-term and long-term studies of the adequacy of MAIN's transmission system. The EC's MAIN Guide 6 study group analyzes the reliability of MAIN's generation system. MAIN works with its neighboring Regions to analyze interregional reliability through its participation in the MAIN-ECAR-TVA (MET) and MAIN-MAPP-SPP (MMS) groups.

The 44 members of the Mid-America Interconnected Network (MAIN) include 14 electric utilities and more than 30 other organizations involved in Regional energy markets. MAIN is a summer-peaking Region serving a population of 19 million in a geographic area of 120,000 square miles encompassing 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 load forecast uncertainty is taken into account, the Region may be capacity deficit by summer 2000 and nearly 5,400 MW deficit by summer 2008. MAPP-U.S. utilities have committed to provide an additional 288 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.

The Mid-Continent Area Power Pool (MAPP) Region has significantly increased its membership with the participation of three transmission-owning members in Kansas, two in Missouri, and three in Wisconsin. These members have joined the MAPP Reliability Committee, Regional Transmission Council, and Power and Energy Market, or all three. In addition, 26 new transmission-dependent companies have joined the MAPP Power and Energy Market and the MAPP Regional Transmission Committee, or both. MAPP membership now totals 102 members and includes 20 transmission-owning members, 55 transmission-using members, 71 Power and Energy Market members, 19 associate members, and eight regulatory participants. As a result of this tremendous growth in membership and power market activity in the MAPP Region, MAPPCOR has increased staff considerably to support Regional security and reliability activities. The MAPP Security Center has been a major focus of activity and is fully operational in 1999.

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, Transmission Reliability, Reserve Requirements, and Model Building Working Groups jointly prepare the MAPP ten-year Regional Reliability Assessment. The Reliability Studies Subcommittee, Design Review Subcommittee, and Operating Review Subcommittee are committed to reviewing MAPP reliability from a near-term and long-term perspective to ensure the MAPP system can meet the needs of its members.

Demand and Energy

The MAPP-U.S. and MAPP-Canada combined 1998 summer noncoincident peak demand was 35,998 MW, an 8.7% increase over 1997 (33,129 MW) and 1.1% below the 1998 forecast (36,392 MW). MAPP-U.S. accounted for 8.5% above 1997 actual demand and 1.0% above the 1998 forecast. MAPP-Canada was 9.5% above the 1997 actual demand and 3.8% below the 1998 forecast.

The MAPP-U.S. summer peak demand is expected to increase at an average rate of 1.8% per year during the 1999–2008 period, as compared to 1.2% predicted last year for the 1998–2007 period. The MAPP-U.S. 2007 noncoincident summer peak demand is projected at 33,026 MW. This projection is 5.5% above the 2007 noncoincident summer peak demand predicted last year. Annual electric energy usage for MAPP-U.S. in 1998 (159,550 GWh) was 3.1% above 1997 consumption and 2.6% above the 1998 forecast.

Resource Assessment

Generating system adequacy for the MAPP-U.S. Region is judged to be inadequate over the 1999–2008 period. MAPP-Canada will be adequate over the ten-year period. Net capacity for MAPP-U.S. (committed and proposed generation additions, uprates, and retirements) will provide an additional 288 MW of capacity in the MAPP-U.S. area for 1999–2008. Committed and proposed capacity additions (new) account for 227 MW, uprates account for 63 MW, and retirements accounts for -2 MW. The summer reserve margin is expected to be below the 1998 forecast and to decline from a high of 19% in 1999 to 15% in 2002 and 2% in 2008 when committed and proposed generation is considered. The MAPP Agreement obligates the member systems to maintain reserve margins at or above 15%. In addition, when a 3% load forecast uncertainty is taken into account, the MAPP-U.S area may be capacity deficit by summer 2000 and nearly 5,400 MW deficit by summer 2008.

Because of the potential generating system inadequacy, the Region 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 7,190 miles of 230 kV, 5,693 miles of 345 kV, and 342 miles of 500 kV transmission lines. MAPP-U.S. members plan to add six miles of 345 kV and 35.5 miles of 230 kV transmission in the 1999–2008 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 494 miles of 230 kV transmission in the 1999–2008 time frame.

MAPP member systems continue to plan for a reliable transmission system. Coordination of expansion plans in the Region takes place through joint model development and study by the Regional Transmission Committee. This committee includes transmission-owning members, transmission-dependent 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, 1998 to 2007, to meet 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. Current studies at MAPP, however, have identified potential restrictions on the transmission system for outages of certain 345 kV lines in the Twin Cities metropolitan area of Minneapolis-St. Paul (e.g., Prairie Island-Byron or King-Eau Claire). These outages may result in system stability restrictions that limit energy transfers from the Twin Cities to Iowa and Wisconsin.

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 operational 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 102 utility and nonutility 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

NPCC is putting in place rigorous processes to ensure continued reliability through full and mandatory compliance with the NERC Planning and Operating Policies and the NPCC Criteria and Guides. NPCC has established the Compliance Monitoring and Assessment Subcommittee to develop the necessary procedures for compliance monitoring and assessment of the NPCC members, an enforcement strategy, and an appeals methodology. The Compliance Monitoring and Assessment Subcommittee is also supervising NPCC's participation in the NERC Pilot Compliance Program. In parallel with this effort, NPCC is reviewing and restructuring all of its Criteria and Guides to better align the NPCC and NERC documents, appending the NPCC specific portions of its Criteria and Guides to the Standards and Requirements of the corresponding NERC document, and creating an augmented, composite NERC/NPCC document.

Currently under study in New York and New England are over 5,400 MW and 32,000 MW of merchant plant activity to be in service by the end of 2002.

NPCC Assessment Process

The NPCC Reliability Assessment Program brings together the efforts of the Council, its member systems, and Areas in the assessment of the reliability of the bulk power system. Over the years, NPCC has developed an extensive set of Criteria, Guides and Procedures (NPCC Documents) that define reliable operation and planning within NPCC, and with which compliance is mandatory on the part of all NPCC members. The Reliability Assessment Program assures that all NPCC documents are reviewed on a periodic basis to ensure that they remain current and timely in their focus. As part of the Program, the Task Force on Coordination of Planning is charged, on an ongoing basis, with conducting reviews of resource adequacy of each Area of NPCC. In a similar manner, the Task Force on System Studies is charged with conducting periodic reviews of the reliability of the planned bulk power transmission systems of each Area of NPCC and the transmission interconnections to other Areas.

The primary objective of the NPCC Area 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 (Document A-2), 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 and monitors the resolution of the possible threat to reliability.

Through the establishment of the Compliance Monitoring and Assessment Subcommittee, the NPCC Reliability Assessment Program has been enhanced to ensure that NPCC will comply with the new NERC Planning Standards and revised Operating Policies. NPCC has additionally embarked on a comprehensive review and restructure of its Criteria and Guides to better align the NPCC and NERC documents, appending the NPCC-specific portions of its Criteria and Guides to the Standards and Requirements of the corresponding NERC document, creating an augmented, composite NERC/NPCC document.

Demand and Energy

The average annual growth rate forecast for the summer peaking United States entities of NPCC for 1999 through 2008 is 1.4%, unchanged from the 1998 forecast; projected annual electrical energy growth rate is 1.5% as compared with the projection of 1.4% for 1998. The net internal demand for the summer peaking United States entities of NPCC is projected to reach 58,577 MW by 2008.

The average annual growth rate for the winter peaking demand for the Canadian members of NPCC is 1.2%, as compared to last year's 1.3% forecast. The winter peaking Canadian members are projected to reach a net internal demand of 66,227 MW by the winter of 2008/2009. The projected annual electrical energy growth rate is 1.3%, as compared with a growth rate of 1.4% projected in 1998.

Resource Assessment

In New England, the NEPOOL average annual growth rate of the summer peak demand for 1999 through 2008 is 1.9%, unchanged from the 1998 projection. Energy growth for the same period is projected to be 2.1% as compared to 1.9%, which was projected last year.

Within the five-year planning horizon, ISO New England is beginning to see the response of the marketplace to anticipated resource needs, with merchant plant activity totaling over 32,000 MW of generating capacity having filed applications with the ISO-NE for the necessary system integration studies. The service dates for the generation facilities, all of which are proposed as gas-fired, range from 1999 to 2002.

In New York, the peak demands that are forecast for the years 1999 through 2008 show an average annual growth rate of 0.9%, which is a slight decrease compared to last year's forecast of 1.0%. The forecast net energy for the same ten-year period also shows a growth rate of 1.1%, up somewhat from the 1998 forecast of 1.0%. The New York Power Pool reserve margin will be adequate over the 1999 through 2002 period, while recognizing the uncertainties facing the industry as a whole over the last five years of the assessment period. The member systems are considering various options for increasing capacity by 2003, including over 5,000 MW of proposed merchant activity.

The New York Power Pool has filed tariffs with FERC to reorganize itself as the New York Independent System Operator (NYISO). At this time, the New York Power Pool is anticipating making the transition to the NYISO during the autumn of 1999. The NYISO will not be able to direct the procurement of resource capability. However, it will be empowered by the New York State Reliability Council to set installed capacity requirements that are consistent with the NPCC reliability criterion. The procurement of installed capacity will be accomplished through an installed capacity market in which each load-serving entity in the New York control area will be required to purchase sufficient capacity to meet installed reserves so that the NYISO installed capacity will be sufficient to meet the NPCC criterion. Failure to do so will result in the imposition of financial penalties.

Ontario's average annual growth rate for 1999/2000 through 2008/2009 is now projected to be 0.9% for the winter peak demand, as compared to a rate of 1.0% reported last year. Energy growth is projected at 1.0% for the same period as compared to last year's value of 1.1%.

Ontario is forecasting adequate levels of resources throughout the reporting period, with IPP capacity at 1,621 MW throughout the ten-year period.

Hydro-Québec's average growth rate of internal demand for 1999 through the winter load period of 2008–2009 is now projected to be 1.7%, which is a reduction from the 1.9% forecast of last year. With this reduction, no new commitments for major projects are required before the 2004–2005 period. Should load growth exceed expectations, options such as capacity purchases or new interruptible load programs can be made available quickly. For the years 2004–2008, over 2,500 MW of uncommitted hydroelectric capacity continues to be studied. Also, Hydro-Québec, Newfoundland and Labrador Hydro have undertaken negotiations for the further development of the hydroelectric potential of the Churchill River in Labrador. These projects could add 2,200 MW on the Lower Churchill River as well as 1,000 MW of capacity at the Upper Churchill. The projected in-service date for both sites is projected for the 2007–2010 time period. Finally, Hydro-Québec's demand for energy will increase at an average annual rate of 1.8% between 1999 and 2008 as compared to the 1.7%, which was projected last year.

In the Maritime Area (New Brunswick, Nova Scotia, and Prince Edward Island), the average annual growth in winter peak demand for 1999 through 2008 is 4.9%, and the corresponding growth in energy is 0.6%, both less by over 1.0% as compared with last year's forecast due to the increasing penetration of natural gas into the electricity market. Planned utility generating unit additions currently total about 30 MW through the forecast period, and projected IPP generator additions are estimated to total about 72 MW.

By the end of the forecast period, gas-fired generation, from both utility and nonutility sources, is projected to supply about 40% of the electrical energy in the U.S. portion of NPCC. Discovery of the Sable gas fields near Nova Scotia has lessened somewhat the concern over the ability of gas suppliers to deliver large amounts of gas to the northeastern United States. Also, as a result of the Sable gas fields, the Maritimes Area of NPCC now projects increasing usage of natural gas for electricity generation during the 1999–2008 period.

Transmission Assessment

The existing interconnected bulk electric transmission systems in New England, New York, Ontario, New Brunswick, and Nova Scotia meet NPCC Criteria and are expected to continue to do so throughout the forecast period. In the U.S. areas of NPCC, planned transmission additions for voltage levels 230 kV and above total 222 miles, all in New England. In Canada, planned transmission line additions during the ten-year forecast period for voltage levels 230 kV and above total 394 miles in Québec and 192 miles in Ontario.

Two projects are planned in NPCC that will relieve heavily loaded transmission interfaces.

In New York, the Marcy Flexible AC Transmission System (FACTS) project is planned to proceed in two phases. Phase 1, scheduled for the year 2000, will include the installation of two inverters at the Marcy substation at Utica and a 135 MVAr shunt capacitor bank at the Oakdale substation near Binghamton. In Phase 1, the inverters will be operated as a dynamic voltage control device (STATCOM). Phase 2, scheduled for the year 2002, will include the addition of 135 MVAr shunt capacitor banks at the Edic and New Scotland substations and will allow operation of the inverters as a dynamic power flow control device. Operation will be possible in the Unified Power Flow Controller, Interline Power Flow Controller, or Static Series Synchronous Compensator power flow control modes. The Marcy FACTS device will be operated to continually optimize the loading of the Marcy-East transmission versus the Marcy-South transmission with respect to thermal and voltage transfer limitations, increasing the transfer capability across the Total-East transmission interface by about 240 MW, which will improve reliability and relieve some of the congestion on that interface.

Ontario and Detroit Edison have proposed a plan to improve the reliability of the interconnected bulk power supply system by adding and modifying transmission facilities on the Michigan-Ontario interface. Additional transformation and phase-shifter control of the interface will be augmented by adding phase-angle regulating transformers to the Scott-Bunce 120 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 PAR control of the interface, 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.

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 NEPOOL and ISO New England, the New York Power Pool, and the five Canadian member systems. The Criteria establish the fundamental principles of interconnected operations among the Areas. Specific operating Guidelines and Procedures provide the system operator with detailed instructions to deal with such situations as: depletion of operating reserve, capacity shortfalls, line loading relief, declining voltage, light load conditions, the consequences of a solar magnetic disturbance, measures to contain the spread of an emergency, and restoration of the system following its loss.

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.

Hydro-Québec, ISO New England, the New York Power Pool, and the Independent Electricity Market Operator (Ontario) serve as the security coordination centers for NPCC. As such, each will exchange necessary security data through the Interregional Security Network (ISN). Further, the NPCC Areas routinely conduct conference calls every week to assess the operating conditions for the coming week, and procedures are in place to initiate emergency conference calls whenever one or more Areas feel it would serve to avoid an emergency.

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, and it is affected only when firm load curtailment is imminent. The LEER procedure was approved by FERC on May 12, 1999, and FERC found that the LEER procedure goes beyond its December 16, 1998 order regarding the filing of transmission loading relief procedures.

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

NPCC is a voluntary, nonprofit organization. Its current membership, of which there are 33, represents transmission providers, transmission customers, power pools, and independent system operators serving the northeastern United States and central and eastern Canada. The NPCC Membership Agreement also allows for nonvoting membership to be extended to regulatory agencies with jurisdiction over participants in the electricity market in northeastern North America and public interest organizations expressing interest in the reliability of electric service in the northeastern North America; there are currently two such Public Interest Members. In addition, NPCC also works closely with a number of associated organizations and NERC.

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

Planned resources are judged to be adequate to meet forecast annual summer peak demand growth of 2.38%. The overall SERC capacity resource margin for the ten-year period is up slightly from the 1998 forecast, reflecting the members' continuing reliance on short lead-time resources and market providers. Many systems in SERC are planning to install or purchase peaking-type capacity during this reporting period.

The ability to transfer power above contractually committed uses, both intra- and interregionally, has become marginal on some interfaces under both studied and actual operating conditions. 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.

Assessment Process

The Reliability Review Subcommittee (RRS) of the Southeastern Electric Reliability Council-Engineering Committee (SERC-EC) annually assesses and reports on the adequacy of reliability studies conducted by the four subregions of SERC. The RRS also assesses the coordination of such studies with other affected subregions or Regions, and the ability of the planned systems to meet SERC and NERC reliability criteria.

The RRS evaluates adequacy and security for a ten-year period based on the SERC "Principles and Guides for Reliability in System Planning." Data for this analysis is provided to SERC by the individual member systems.

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.

In June 1999, the RRS completed its 20th annual review of subregional expansion plans and the process of coordination of planning among the SERC subregions and between SERC and adjacent Regions.

Demand and Energy

The SERC 1998 summer peak demand of 142,506 MW represented a 3.8% increase from the 1997 summer peak of 137,382 MW, and was 5.6% higher than forecast. The 1999–2008 forecast of average annual growth in summer peak demand has increased from last year's 2.03 to 2.38%. Forecast growth rates have not varied widely. The summer peak demand projected for 2007 (the last common year of the last two forecasts) is 5,593 MW higher than projected last year.

Annual electric energy usage in 1998 was 747,684 GWh, which was 2.39% greater than the 730,248 GWh of electric energy usage in 1997. The forecast growth rate in energy usage is 2.25%. The historical SERC growth rate (excluding the Entergy subregion) for the last ten years is 2.92%.

Resource Assessment

Planned resources are judged to be adequate to meet forecast annual summer peak demand growth for the 1999–2008 period. Net capacity additions within SERC for the 1999–2008 period total 36,040 MW. These additions include combustion turbine units (32.5%), combined cycle (27.4%), and unspecified other (36.5%).

The overall SERC capacity resource margin for the ten-year period is up slightly from the 1998 forecast. The 1999 forecast shows margins ranging from a high of 13.65% in 2000 and 2002 to a low of 11.54% in 2008. Although the systems in SERC do plan to maintain capacity margins at or above 11% over the reporting period, nearly 79% of the planned capacity additions in the next ten years are uncommitted, undefined resources. The committed capacity margin is calculated by removing all resources that are not currently under construction or permitted and computing the resulting capacity margin against projected summer peak demand. The Regional committed capacity margin drops below 10% in

2002 and below 5% in 2004, indicating that the SERC Region is relying heavily on peaking capacity that must be contracted for, planned, and constructed in a short but manageable time period.

Based on its review of the 1999–2008 period, SERC's committed capacity margins appear adequate for the Region in view of the significant commitment by member systems to short lead-time resources. The Region and its member systems must continue to carefully monitor this capacity margin lead time to ensure that proper resource development is pursued to maintain Regional reliability.

Transmission Assessment

The existing bulk transmission system within SERC is comprised of 18,834 miles of 230 kV, 695 miles of 345 kV transmission lines, and 8,744 miles of 500 kV transmission lines. SERC systems plan to add 944 miles of 230 kV and 154 miles of 500 kV lines in the 1999–2008 period. No additional 345 kV transmission lines are planned during this period.

SERC member systems continue to plan for a reliable bulk transmission system. Coordination of transmission expansion plans in the Region is maintained by joint modeling efforts among member systems. The ability to transfer power above contractually committed uses, both intra- and inter-regionally, has become marginal on some interfaces under both studied and actual operating conditions. 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.

The increase in bulk power marketing activity resulting from the transmission open access tariffs continues to push the operating state of the transmission system into conditions for which it was not originally planned. SERC member systems need to take a proactive role in advocating the continued planning and operation of the system in a manner that meets NERC and SERC reliability criteria.

Operations Assessment

SERC has implemented several measures in the last few years to ensure reliability of the system. There are five security coordinators in SERC — one in each of the Entergy, Southern, and TVA Subregions, and two in the Virginia-Carolinas Subregion. In addition, line loading relief procedures have been implemented since the summer of 1997. The SERC ATC Working Group has continued to refine the SERC ATC procedures to improve the overall process and to comply with the NERC requirements.

SERC member systems jointly perform seasonal operating studies and coordinate operations. The establishment of security coordinators and the sharing of real-time information have provided significant reliability benefits for operating the system.

Southeastern Electric Reliability Council (SERC) membership includes 38 members and 32 associate members. The Region, represented by the Council, is located in 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 Southern, Tennessee Valley Authority, the Virginia-Carolinas Area, and Entergy.

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 for at least one year. Beyond that point, it is somewhat difficult to assess the bulk transmission system because, for the last two years, SPP has not performed any analyses on a coordinated basis beyond ATC determinations for the next five seasons. However, those deferred coordinated analyses are planned to recommence later this year. The last coordinated analyses performed indicate that the bulk transmission system would be reliable over the long term if sufficient lead times exist to add the transmission facilities necessary to accommodate longer-term generation additions. SPP has already found that insufficient lead time exists to add transmission facilities to accommodate some of the generation additions planned for the short term.

Assessment Process

The SPP Reliability Assessment Working Group (RAWG) reports directly to the SPP Board of Directors in an "auditor" role. The RAWG reviews (and summarizes in SPP's Annual Report) the many detailed studies performed by SPP organization groups throughout the year. The RAWG tracks and documents SPP bulk electric system reliability and highlights areas that, if unsuccessfully managed, will threaten service continuity.

RAWG reviews member projections of load demand, capability, and capacity margin. RAWG analyzes how future resource needs are planned to be met such as through committed versus uncommitted new capacity, unknown or undermined capacity, units returned to service, and demand-side management. In addition, RAWG reviews loss-of-load-expectation (LOLE) analyses performed by another SPP working group.

RAWG reviews the studies performed by the Transmission Assessment Working Group (TAWG). TAWG performs seasonal power flow studies for purposes of determining Available Transfer Capabilities for transmission system interfaces between member systems. In addition, TAWG participates in interregional studies with other Regions.

Demand and Energy

SPP is a summer-peaking Region with projected annual peak demand and energy growth rates of 2.0 and 2.1%, 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 lower than the ten-year historical growth rates of 2.4 and 3.0% for peak demand and energy, respectively.

Members are focusing more on the short term (two to five years), thereby shrinking the planning horizon. This reduces the need for long-term (five to ten years) forecast accuracy. The projected growth rates for peak demand and energy over the next five years are 2.0 and 1.9%, respectively. The actual growth rates for peak demand and energy over the last five years were 1.7 and 2.6%, respectively.

Resource Assessment

During 1998, the SPP Board of Directors approved new reliability criteria that requires a 12% capacity margin, effective October 1, 1998.

The former criteria allowed members to reduce their minimum capacity margin target from 15.25% to 13.0%, if studies indicated that their expectation of demand exceeding generation is not greater than one occurrence in ten years. Some members had reduced their capacity margin criteria in this way.

For the most part, SPP members are assuming that the market will provide needed resources or that new uncommitted capacity sources could be made available by those members in a two- to three-year time period. Committed capacity margins are expected to be 11% in 2000, 13% in 2001, and 12% in 2002. These margins are based on EIA 411 information, except the uncommitted capacity additions and "unknown" purchases contained therein are excluded.

The EIA-411 information does not reflect some 6,000 MW of merchant plant additions being planned for the 2001 to 2002 time period. The above capacity margins would increase about two percentage points for each 1,000 MW of the merchant plant capacity that is added. About half of this planned merchant plant capacity cannot be built by that time period because of the lead time for the transmission facilities required to accommodate that capacity. This lead-time problem is discussed further in the Transmission Assessment portion of this report.

The amount of current merchant plant activity is in stark contrast to that of only one year ago. Last year, based on available information, merchant plant activity was practically nonexistent.

Though SPP has never experienced loss of firm customer demand due to a capacity shortage, lower margins may challenge this trend in the future. It is becoming very difficult to assess generation reliability in the increasingly competitive market place. While economic theory states that the market place will meet demands, system operators had difficulty finding access to resources, regardless of price, in the past several years. This is occurring more frequently.

The LOLE studies performed by SPP show that an adequate capacity margin for SPP is very sensitive to small changes in unit availability. Availability studies do show improvements in unit availability over the past several years, and members are committed to continuing this trend.

An increasingly important factor in the LOLE studies will be the reliance on resources outside the individual member's areas and outside SPP. As capacity margins dwindle and SPP's members and those of other Regions rely more and more on the "market" to supply the necessary capacity to serve their customers, the reliability of those outside resources must be studied carefully.

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 no significant impact 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 were performed on the bulk transmission system for the next five seasons on a coordinated basis. These calculations account for the most restricting credible operating contingency.

The bulk transmission system is adequate for the five seasons covered by the ATC analyses. Beyond that point, it is somewhat difficult to assess the bulk transmission system because, for the last two years, SPP has not performed on a coordinated basis any analyses beyond those ATC determinations. However, those deferred coordinated analyses are planned to recommence later this year.

The last coordinated analyses performed indicate that the bulk transmission system would be reliable over the long term if sufficient lead times exist to add the transmission facilities necessary to accommodate longer-term generation additions. SPP has already found that there is insufficient lead time to add transmission facilities to accommodate some of the generation additions planned for the short term.

This lack of sufficient lead time for adding transmission to accommodate new generation is becoming more and more of a problem. During 1999, merchant developers have requested transmission-planning studies to determine the transmission additions needed to tie their planned generating plants into the bulk transmission system. These plants total several thousand megawatts of new generating capacity. In some cases, over 100 miles of new transmission lines are required. Sufficient time does not exist to build that transmission prior to the planned operation date of the new capacity.

Transmission planning to accommodate new generating capacity is further encumbered by the fact that all of the affected systems are not aware of planned generation within SPP or in neighboring NERC Regions. Merchant developers approach the local utility and request transmission analyses for their new generation projects. Other utilities, whose transmission systems may be significantly affected by these projects, are oftentimes unaware of the projects.

In addition, SPP has experienced the situation where one utility was performing a transmission planning analysis for delivering output from a new generation project from point A to point B, while another utility was performing a transmission planning analysis for delivering output from a different new generation project from point B to point A. Initially, these two utilities were unaware of each other's analyses.

Transmission planning is further complicated because these developers do not know the destination of the power from its projects and thus request analyses for multiple destinations. Further, in performing transmission impact studies for new generation projects, some utilities pancake one request upon another, while others study each request individually. Moreover, transmission planning is further complicated because some of the generation projects being analyzed may not materialize.

Longer-term transmission planning is being complicated by such things as the modeling of transactions resulting from the introduction of retail access, difficulties in acquiring right-of-way, and EPA restrictions.

These factors point to the need for more coordination of transmission planning within SPP as well as between SPP and adjoining Regions. SPP is working toward ensuring that this coordination is obtained.

Operations Assessment

SPP operated without a security center until installation of one in late 1997. The security center, located at the SPP offices, provides the exchange of near real-time operating information and around-the-clock security coordination.

Line loading relief procedures have been developed in accordance with NERC's Operating Policies. These procedures include preemptive screening, performed daily, to help members recognize heavy line loading that is expected to occur. A major tenant of these procedures is to ensure that line loading relief is cured by real changes in generation patterns, not a mere shuffling of interchange schedules. SPP has experienced considerable line loading relief in recent years and expects that it will continue in the future.

SPP continues toward the formation of a Regional Transmission Organization or Independent System Operator. The SPP is working toward FERC's ultimate objectives — independent regional security coordination and independent regional tariff administration.

Compliance Enforcement

The interstate high-voltage transmission system — the backbone of the nation's electricity infrastructure — is critical to public health, safety, welfare, and national security, and enables robust competition in electricity markets in the United States and throughout North America. The existing voluntary system for setting and encouraging compliance with industry reliability standards for the transmission system is not sustainable in today's increasingly competitive electricity industry. However, reliability of this system need not be compromised, provided appropriate steps are taken. Reliability rules must be made mandatory and enforceable, and those rules must apply fairly to all entities that own, operate, and use the transmission system. Federal legislation is needed to provide an enforcement framework for mandatory compliance.

SPP has 51 members serving all or parts of Arkansas, Louisiana, Mississippi, Missouri, Kansas, Oklahoma, Texas, and New Mexico. The Region monitors, coordinates, promotes, and communicates information on the reliability of the electricity supply systems through the dedicated efforts of more than 370 people from member systems. The Board of Directors has responsibility for overall policy direction, and an administrative and technical staff located in Little Rock, Arkansas provides day-to-day coordination.

WSCC

Transmission system reliability is expected to be adequate throughout the ten-year period based on the annual study report and ongoing seasonal operating transfer capability assessments of major interties.

Projected resource capacity is expected to be adequate for the assessment period throughout WSCC.

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

The projected capacity margins and fuel supplies are anticipated to be adequate to ensure reliable operation in all areas of the Region. The capacity margin adequacy over the next ten years presumes the timely construction of approximately 11,300 MW of new generation, full utilization of over 10,000 MW of internal WSCC demand diversity, and the acquisition of up to 2,399 MW of additional resources and/or demand curtailment capability in Alberta, Canada. The capacity margin adequacy also presumes 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's schedule tracking system records schedules between control areas from the original source to the final destination. This tracking system is designed to improve frequency control and increase system operator effectiveness in responding to transmission system outages. WSCC's unscheduled flow mitigation plan is in effect to help control unscheduled flows within the Region and enhance operating efficiency through the coordinated operation of phase-shifting transformers at key locations.

Under WSCC's Regional Security Plan, three security centers have been established for the Region.

The security center coordinators are charged with actively monitoring, on a real-time basis, interconnected system conditions to anticipate and mitigate potential reliability problems and to coordinate system restoration should an outage occur.

In the following text, several issues are mentioned that could pose significant challenges to the preservation of reliability in varying degrees:

- competition and increasing pressures to reduce costs,
- changes in the structure of the electric industry, and
- uncertainty regarding load growth projections and the planning and installation of new generation.

Through active participation in the WSCC Regional Reliability Council, individual member participants will be able to manage these issues and maintain a balance between reliability and the economic pressures of competition. WSCC is an open forum for all entities that have a stake in the planning and operation of the interconnected electric system in western North America, enabling them to actively share in the responsibility of maintaining this essential balance.

WSCC Assessment Process

The WSCC Region follows 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.

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 expected to be adequate throughout the WSCC Region for the 1999 through 2008 ten-year period. The assessment assumes that approximately 11,300 MW of net new generation will be built when and where needed, that over 10,000 MW of internal WSCC demand diversity will be available when and where needed, and that up to 2,300 MW of additional resources and/or demand curtailment capability will be available in Alberta, Canada.

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 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 being effected that reduce the likelihood of widespread system disturbances include: a southern island load tripping plan, a coordinated off-nominal frequency load shedding and restoration plan, and enhancements to the processes for conducting system studies.

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 least once every five years to assess compliance with WSCC and NERC operating criteria.
- Annual Study Report — 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.

Reliability Management System

WSCC officially implemented Phase 1 of its Reliability Management System (RMS) on September 1, 1999 after a 19-month evaluation period. WSCC's RMS program is a first-of-a-kind sanction-based program to maintain reliability, and represents a significant milestone for the WSCC members and the electric industry.

The program, developed voluntarily through a public open process involving the WSCC membership; the regulatory community; and other interested stakeholders, provides for the enforcement of sanctions for noncompliance through contracts that are signed by WSCC and each RMS participant. WSCC was granted a Declaratory Order by the Federal Energy Regulatory Commission (FERC) and received a Business Review Letter from the Department of Justice enabling WSCC to proceed with RMS implementation in early 1999. FERC issued an order on July 29, 1999 accepting the RMS contracts. As of early September, 26 WSCC members, representing a substantial number of the WSCC control areas, have signed the RMS agreements.

Phase 1 of RMS requires compliance with the following criteria:

- control performance,
- operating reserve and operating transfer capability,
- disturbance control, and
- generating unit automatic voltage regulators and power system stabilizers.

The control performance standards, operating reserve, and operating transfer capability requirements are assessed monthly and the disturbance control standard and requirements for power system stabilizers and automatic voltage regulators are assessed quarterly.

Phase 2 of the reliability management system is presently under evaluation and development. Phase 2 includes requirements for:

- interchange schedule tagging,
- availability of operating limits to system operators on major transmission paths,
- protective relay and remedial action scheme application certification,
- protective relay and remedial action scheme misoperation, and
- communication and coordination of operational system data.

On the basis of these ongoing activities, transmission system reliability of the Western Interconnection is projected to be adequate throughout the ten-year period.

Northwest Power Pool Area

The Northwest Power Pool (NWPP) Area is comprised of the states of Washington, Oregon, Idaho, and Utah; the Canadian provinces of British Columbia and Alberta; and portions of Montana, Wyoming, Nevada, and California. Over the period from 1998 through 2008, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 1.1 and 1.6%. Resource capacity margins for this winter peaking area range between 11.3 and 15.7% of firm peak demand for the next ten years.

The internal NWPP Area transmission capability is expected to permit anticipated transfers between NWPP systems under most conditions during 1999. Should a contingency occur, such as very high peak demands during a period of extreme cold weather, the Pacific Northwest may need to rely on the capability to import power. Current studies show that import capability into load centers will be adequate under moderate and extreme weather conditions. Operating procedures and operational indicators to monitor loadings on key facilities have been developed to ensure that, if needed, the Pacific Northwest could import power at safe, reliable levels.

The North-to-South spring operating transfer capability of the combined California-Oregon Intertie, the new Northwest-to-Sierra Intertie, and the Pacific DC Intertie is 7,900 MW. Studies demonstrate a reliable operating transfer capability of 7,570 MW for this summer.

The transmission interconnections between the province of British Columbia and the state of Washington have several restrictions due to unscheduled flows. Joint studies by affected organizations are being undertaken to identify and resolve system conditions that interfere with electricity trade opportunities.

A Northwest Operational-Planning Study Group prepares transfer capability studies for all major Northwest paths in a coordinated, subregional approach for submission to WSCC's Operating Transfer Capability Policy Group. Study plans have been submitted for the upcoming summer, and other seasonal studies will follow as appropriate.

The May preliminary forecast of Columbia River runoff for the period January through July, as measured at The Dalles, is about 124 million-acre feet, or about 117% of the most recent 30-year average. The record runoff of 159 million-acre feet, or about 150% of average, occurred in 1997. The volume forecast in the Canadian Upper Columbia is about 106% of average.

Coordinated system storage energy as of July 31, 1998 reached 99% of allowable refill, establishing first-year firm load carrying capability for operation in 1998/99. The actual reservoir refill was 94% full. This was the third consecutive year that the system was declared essentially full, after four low refill years in the early 1990s. It is expected that reservoirs will again refill to about 95% of full content by July 31, 1999.

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 1998 through 2008 period, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 2.2 and 2.4%. Summer resource capacity margins range between 17.1 and 22.5% of firm peak demand for the next ten years.

In July 1998, Colorado experienced loss of firm customer load due to the unscheduled outage of generation and the loss of transmission transfer capability. Several actions have been taken to reduce the probability of recurrence this summer. These actions include additional transmission line right-of-way tree clearing and generating capability increases of about 300 MW.

The Rocky Mountain Reserve Group (RMRG) was granted final FERC acceptance in January of 1999, and is operational. The RMRG better meets the FERC conditions and the WSCC ten-minute response and hourly reserve requirements than the former Inland Power Pool it replaces. The RMRG members are obligated to maintain defined levels of reserves on an hourly basis, to coordinate reserve sharing and reserve activation within ten minutes for unanticipated loss of generation, and to provide emergency assistance when firm load is at risk. The RMRG will increase the efficiency of the use of generation, transmission, and interconnections while lowering the amount of reserves each member would have to maintain in the absence of the group.

The transmission system in the subregion has been reinforced. A 230 kV double circuit line has been added between Nixon station and the Cottonwood and Jackson Fuller substations. This line, coupled with a reconfiguration of the Comanche-Daniels Park 230 kV line, creates a stronger and more reliable tie between Pueblo, Colorado Springs, and Denver. The Pawnee-Story 230 kV line was reconductored, allowing higher transfers across the TOT 3 path, particularly when the 495 MW Pawnee Station generator is out of service. A 210 MW back-to-back DC tie between WSCC and SPP is scheduled for 2004. This interconnection will be powered through a 300-mile, 345 kV transmission line from Potter County, Texas to Lamar, Colorado. The subregion's reactive capability is being improved through the addition of about 300 MVAr of shunt capacitors in 1998 and 1999.

Hydroelectric generation is expected to be slightly above normal in the northern Rocky Mountains and near normal in the central Rocky Mountains. Water inflows into the South Platte, North Platte, Colorado, Big Thompson, and Green Rivers are expected to be near normal this year as snowpack is about 100% of normal in these river basins. Water inflows into the Missouri River are expected to be approximately 115% of normal this year. Reservoir storage is in good condition and hydroelectric generation is expected to be near the long-term average. The Glen Canyon power plant is operating under environmental impact restrictions that limit water releases. The 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 1998 through 2008 period, peak demand and annual energy requirements are projected to grow at a 2.5% annual compound rate. Resource capacity margins for this summer peaking area range between 9.4 and 10.6% of firm peak demand for the next ten years.

Significant amounts of shunt capacitors and series compensation have been and are being installed in order to preserve reliability in the area. Several southwestern utilities are planning to either install combustion turbine generators or make purchases of peaking power from independent power producers. Many southwestern systems have joined or become correspondents to the Southwestern Regional Transmission Association (SWRTA), a regional transmission group. The group provides subregion planning to accommodate wheeling requests resulting from the Energy Policy Act of 1992 (EPACT). The SWRTA planning committee is working on implementing transmission access requirements associated with EPACT and developing a subregional plan.

The major generating plant operators in the area have created a Southwest Reserve Sharing Group. This group will be sharing contingency reserves with a computer-assisted communication system for activating reserves in the form of emergency assistance to recover from group disturbances within the ten-minute recovery criteria.

The restructuring of the electric utility industry has seen the Southwest utilities investigating the feasibility of an independent system operator (ISO) to be called Desert STAR (Desert Southwest Transmission and Reliability Operator). The main goals of Desert STAR are to provide electrical system security and reliability in accordance with NERC and WSCC Policies and to provide nondiscriminatory open access to the transmission system. The Desert STAR initial feasibility evaluation was completed in September 1997. A development agreement has been entered into by more than 50 entities to further define the role and responsibilities of the proposed ISO during 1999.

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 in 1998 and beyond adds 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 1.3 and 1.8% from 1998 through 2008. Projected resource capacity margins range between 10.7 and 12.1% 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. The curtailments occurred in conjunction with the loss of nearly 2,000 MW of capacity due to forced outages at several power plants. Peak demand forecasts have risen sharply as a result of the experiences of last summer.

The California Independent System Operator (CISO) assumed operational control of the transmission grid of the three California investor-owned utilities on March 31, 1998. The CISO is responsible for several functions including: providing nondiscriminatory, open access to the transmission grid; controlling dispatch and maintaining reliability of the transmission grid; procuring and providing ancillary services; coordinating day-ahead and hour-ahead power scheduling and real-time power balancing; performing settlement function for unscheduled transactions and ancillary services; administering congestion management protocols; and billing.

The CISO has developed a coordinated planning process that will form the basis for planning future changes and additions to the transmission system. The process calls for stakeholder participation in the planning process with the intent to facilitate the development of projects that best meet the needs of all users while maximizing the potential benefits to California.

Western Systems Coordinating Council (WSCC), with 84 members and 17 affiliate 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 (65% of installed capacity); the Rocky Mountain Power Area, which can be either summer or winter peaking with a 24% hydroelectric and 59% coal-fired generating capacity mix; the Arizona-New Mexico-Southern Nevada Power Area, which is summer peaking with a 17% nuclear and 44% coal-fired generating capacity mix; and the California-Mexico Power Area, which is summer peaking and heavily dependent on gas-fired generating units (47% of installed capacity).

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