2003 SUMMER ASSESSMENT

Reliability of the Bulk Electricity Supply in North America

North American Electric Reliability Council

May 2003

Table of Contents

Introduction

This independent assessment of the reliability of the bulk electricity supply and demand in North America for the period June through September 2003 was prepared by the Reliability Assessment Subcommittee (RAS) of the NERC Planning Committee.

Expected electric demand and resources available to meet that demand this summer assessed in the report are based upon data submitted as of April 30, 2003. Transmission reliability issues are also addressed. This report does not make projections or draw conclusions regarding expected electricity prices for the summer.

About NERC

The mission of the North American Electric Reliability Council (NERC) is to ensure that the bulk electric system in North America is reliable, adequate and secure. Since its formation in 1968, NERC has operated successfully as a voluntary organization, relying on reciprocity, peer pressure and the mutual self-interest of all those involved. Through this voluntary approach, NERC has helped to make the North American bulk electric system the most reliable in the world.

NERC is a not-for-profit corporation whose members are ten Regional Reliability Councils. The members of these councils come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. These entities account for virtually all the electricity supplied and used in the United States, Canada and a portion of Baja California Norte, Mexico.

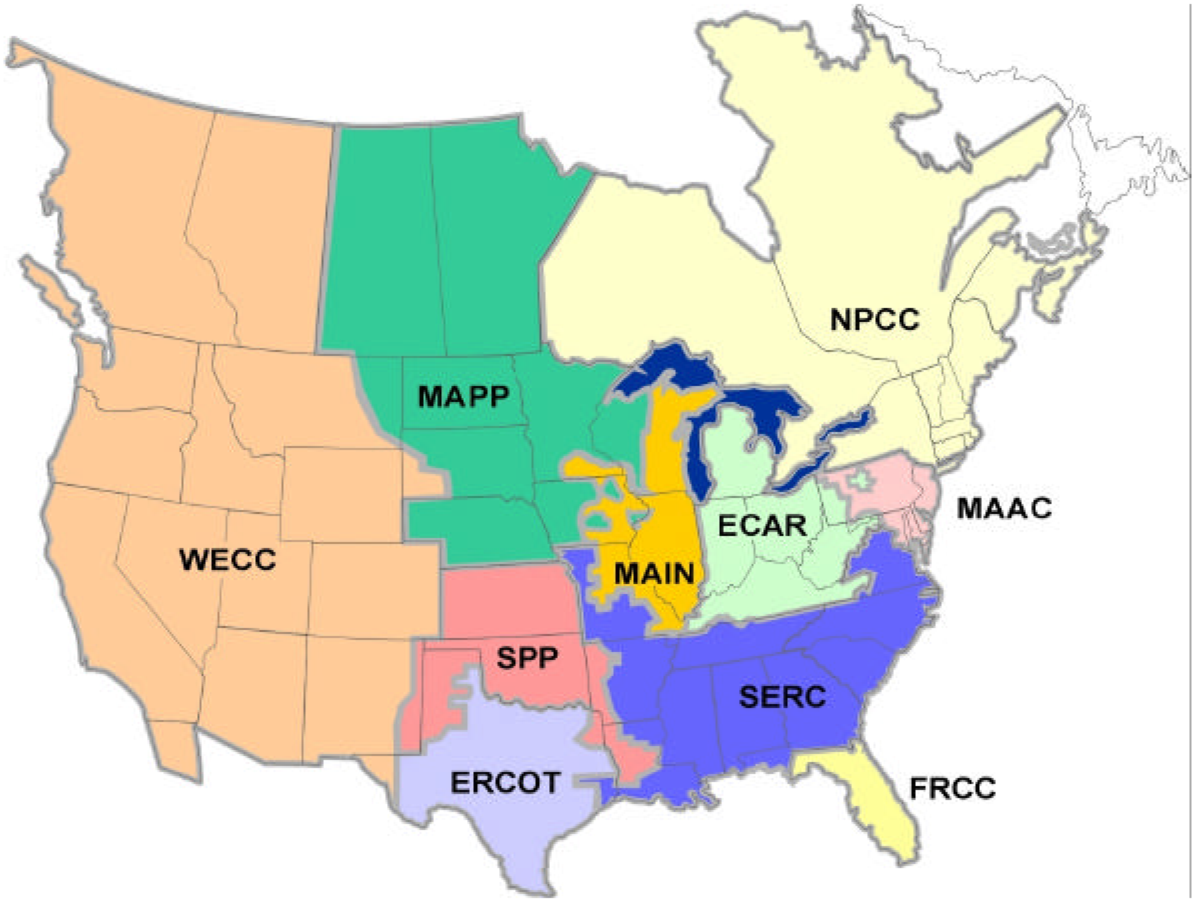


Figure 1: NERC Regional Reliability Councils

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

FRCC
Florida Reliability Coordinating Council

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network, Inc.

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WECC
Western Electricity Coordinating Council

Assessment Summary

Generating resources are expected to be adequate to meet projected demand for electricity in North America this summer. However, there are some areas of concern in NPCC: southwestern Connecticut, New York City and Long Island. Locally tight resources compounded by transmission limitations into and within those areas make them particularly susceptible to reliability problems that can be caused if there is lower than expected generating unit availability, or high demand caused by extreme weather.

Even in areas where resources are expected to be adequate, unanticipated equipment problems and extreme weather can combine to produce situations in which demands temporarily exceed available generation and transmission capacity.

Additional detail is available in the Regional sections of this report.

Demand Projections

The peak demand for electricity in North America is projected to increase 1.0% compared to the actual 2002 noncoincident summer peak, and 1.5% compared to the projected peak demand for summer 2002. It is more meaningful to compare the projected 2003 and 2002 demands because actual demands include weather effects and projections are based on average historical weather conditions.

The relatively flat growth in the projection for this summer compared to 2002 is reflective of the slowdown in the North American economy. To put this growth rate in perspective, the historical average annual demand growth for the last ten years has been about 2.5%.

Demand growth varies widely among the Regions; some expect significant increases in their peak demand for the summer while others project declines.

Table 1: Regional Summer Peak Demand Comparisons for 2002 and 2003

Region [1]	Summer 2003 Projection [2]	% Change Summer 2002 Actual	% Change Summer 2002 Projection
ECAR	100,714	(0.4)	1.4
ERCOT	57,639	2.5	(0.5)
FRCC	41,618	3.4	3.7
MAAC	56,257	1.2	3.8
MAIN	57,312	3.6	0.5
MAPP	35,168	1.1	4.8
NPCC	103,526	(1.6)	3.4
SERC	157,371	0.0	(1.0)
SPP	40,126	1.4	(2.1)
WECC	136,587	0.4	2.5
NERC	783,735	1.0	1.5

[1] Regions are not expected to reach their peak demand simultaneously.
[2] Demand values listed are the projected total internal demand and are weather-normalized; actuals are not. Some interruptible demand or direct control load management may have been activated at the time of the actual summer peak demand.

Supply Adequacy

Generating resources are projected to be adequate in all NERC Regions. Capacity margins used to judge reliability in this report only include capacity committed to serve demand (i.e., that are owned or purchased by load-serving entities) for most Regions. Those capacity values do not necessarily reflect all of the generation located within each Region.

Significant amounts of new generating resources have been added in several Regions since last summer and projected capacity margins have likewise increased, especially in ECAR, ERCOT, NPCC, SERC, WECC, and SPP. Capacity margins in all other Regions are similar to those reported for summer 2002. Despite recent announcements that planned new generators will be delayed or canceled, most units planned to be in service this summer are still on schedule and are expected to be available to serve peak demand.

Although a large portion of the continent is experiencing drought or below average rainfall conditions, this is not expected to lead to capacity shortages this summer.

Generation Resource Changes — Table 2 shows the projected change in reported generation capacity by Regions for their non-coincident projected peak demand month.

Table 2: Regional Summer Resource Projections for 2002 and 2003

	Projected Available Resources[1]			Net Generation Changes[2] Expected
Region	Summer 2003 (MW)[3]	Summer 2002 (MW)[3]	Change (%)	March–September 2003 (MW)
ECAR	125,735	122,754	2.4	5,805
ERCOT	77,563	75,600	2.6	3,665
FRCC	46,459	44,735	3.9	1,215
MAAC	65,308	63,612	2.7	1,606
MAIN	63,127	62,073	1.7	(774)
MAPP	41,851	39,864	5.0	911
NPCC	140,967	123,176	14.4	5,570
SERC	177,398	175,796	0.9	4,295
SPP	47,590	47,727	(0.3)	535
WECC	177,422	166,299	6.7	12,761
Total	963,420	921,636	4.5	35,589

[1] It is not possible to obtain the projected available resources for 2003 summer by simply adding the available resources for 2002 summer to the net generating changes listed in Table 1. Available resources include the varying impacts of purchases and sales, unit maintenance outages, unit uprates/derates, etc. Also, Regional peaks do not occur simultaneously.
[2] The generation changes listed are only those planned for service during the summer months, as reported by the Regions in Appendix 1. Other new generation has been added since last summer, and is already included in capacity resources figure.
[3] Generation listed reflects availability for each Region's projected peak demand month.

Transmission Adequacy

Regional and interregional transfer capability study results indicate that North American transmission system is expected to perform reliably this summer. However, operating experience shows that market conditions can, at times, cause volatile and unpredictable flow patterns that cannot be reliably accommodated by the transmission system. This is further exacerbated by the large amounts of uncommitted generation resources in certain areas. When transmission congestion occurs, congestion management procedures will be implemented to avoid violating system operating security limits.

Fuel Supply

The Regions have reported that fuel supplies, inventories, and deliveries are expected to be adequate this summer. Fuel mix as a percentage of reported generation capacity is shown in the Regional section of this report.

Physical and Cyber Security

In light of recent world events, heightened security is in place throughout the electric industry. NERC, as the Information Sharing and Analysis Center (ISAC) for the electricity sector, works with federal, state, provincial and local organizations, and the industry to monitor the activities under way to protect the physical and cyber elements of the North American electricity system. When conditions warrant, NERC coordinates security alerts throughout the industry to protect the electric system infrastructure.

Areas of Concern

Southwestern Connecticut (NPCC) — During extreme conditions (high levels of generation outages or higher-than-projected demand), the southwestern Connecticut load area may experience reliability problems due to transmission constraints into and within that region. Connecticut Light and Power Company has implemented an emergency plan to address several key contingencies to meet the area's critical near-term electric system reliability needs for this summer.

New York City and Long Island (NPCC) — While resources are expected to be tight again in New York City and Long Island, there are adequate generating capacity and demand response programs in each locality to meet their New York State mandated installed capability requirements.

Any delay in the repair of the existing underwater cable from Norwalk Harbor, Connecticut to Northport, Long Island, may impact reliability in the Long Island load zone. Repairs are scheduled for completion before the summer peak. The commercial operation of the New Haven Harbor, Connecticut, to Shoreham, New York (Long Island), HVDC merchant transmission facility continues to be delayed by regulatory issues. Last summer the United States Department of Energy (DOE) granted an emergency order for operation of the new facility during capacity emergencies, but a similar permit has not yet been granted for 2003 summer.

Areas of Interest

Ontario (NPCC) — Ontario could be heavily dependent on imports to serve its requirements if unexpected hot weather occurs in May and June before the scheduled restart of two of three nuclear units from long-term outage. For the remainder of the summer, if that generating capacity (2,000 MW) is returned to service as planned, resources are forecast to be adequate; if not, Ontario could remain heavily dependent on imports to serve its requirements. In that case, sufficient imports are expected to be available throughout the summer, although requirements could approach the coincident import capability of approximately 4,000 MW at times. Current information indicates that activity milestones for returning that generation to service are being met with only minor delays, providing some confidence that the planned return-to-service dates are achievable.

SERC — There has been significant merchant generation development in SERC during the past few years. Most of this generation has not been committed to serve load within SERC and technical analysis has not necessarily been performed to assure deliverability of all of that capacity to potential markets. Therefore, the additional capacity has not been included in the capacity margin reported for SERC. Although the projected 2003 summer capacity margin is 14.4%, SERC estimates that there may be as much as 46,000 MW of additional capacity that has not been committed to serve load in the Region. If added to committed resources, the connected generation is 45% greater than forecast demand.

Wisconsin (MAPP to MAIN) — Constrained interfaces such as MAPP–MAIN continue to require special operating attention and procedures to maintain reliable operation. American Transmission Company has proposed a 345 kV line between Minnesota and Wisconsin that will help to relieve constraints associated with imports into Wisconsin, and MAIN imports from MAPP. This proposal is under re-examination by Wisconsin regulators. However, this reinforcement is not planned for completion until summer 2007.

Michigan–Ontario Transfers (ECAR to NPCC) — The Michigan–Ontario Phase Angle Regulator (PAR) project has been further delayed and its completion is not expected until after the summer. This delay will reduce the transfer capability of the Michigan–Ontario interface and the ability to control parallel flows. As a result, the Michigan–Ontario interface and the Queenston Flow West interface in Ontario will continue to be susceptible to Transmission Loading Relief (TLR) curtailments.

Transfers from Michigan to Ontario are expected to be reduced by about 150 MW on occasion until about the end of July due to the forced outage of circuit B3N in Ontario as the result of a tower failure. Transfers from Ontario to Michigan are not expected to be affected.

California (WECC) — A recent 500/230 kV improved situation transformer failure in the California ISO will limit north-to-south transfers within California until a replacement transformer bank is installed in late summer. Operating procedures may have to be implemented during high demand periods to limit flows on critical facilities.

Rocky Mountain Power Area (WECC) — Drought conditions in the Rocky Mountain Power Area have been eased by heavy early spring snowfalls. Water inflows into the hydro system are expected to be slightly below average this year. However, since much of the area's hydro system is designed for multiple dry years, the current below-average reservoir storage conditions are not expected to affect adequacy of supply.

Table 3: Estimated 2003 Summer Resources, Demands, and Margins

	June				July			
	Available Resources [1] (MW)	Net Internal Demand [2] (MW)	Available Capacity Margin [3] (%)	Available Reserve Margin [4] (%)	Available Resources [1] (MW)	Net Internal Demand [2] (MW)	Available Capacity Margin [3] (%)	Available Reserve Margin [4] (%)
United States								
ECAR [5]	124,719	92,629	25.7	34.6	125,735	97,758	22.3	28.6
ERCOT	77,357	52,005	32.8	48.7	77,357	55,563	28.2	39.2
FRCC	46,459	37,252	19.8	24.7	46,459	38,368	17.4	21.1
MAAC	65,308	51,839	20.6	26.0	65,308	54,984	15.8	18.8
MAIN	63,165	47,735	24.4	32.3	63,127	54,103	14.3	16.7
MAPP	34,819	26,864	22.8	29.6	34,825	28,493	18.2	22.2
NPCC	68,526	52,025	24.1	31.7	69,067	56,550	18.1	22.1
NYISO	36,817	29,500	19.9	24.8	37,349	31,430	15.8	18.8
ISO NE	31,709	22,525	29.0	40.8	31,718	25,120	20.8	26.3
SERC [6]	176,726	142,276	19.5	24.2	177,398	151,811	14.4	16.9
Entergy	30,418	22,939	24.6	32.6	30,418	24,541	19.3	23.9
Southern	50,915	41,375	18.7	23.1	51,566	45,032	12.7	14.5
TVA	31,869	27,006	15.3	18.0	31,891	27,810	12.8	14.7
VACAR	64,455	50,956	20.9	26.5	64,454	54,428	15.6	18.4
SPP	47,590	35,551	25.3	33.9	47,590	38,646	18.8	23.1
WECC [6]	153,247	110,159	28.1	39.1	152,929	116,807	23.6	30.9
NWPP [7]	48,199	31,388	34.9	53.6	48,681	32,892	32.4	48.0
RMPA	11,538	9,450	18.1	22.1	11,530	10,084	12.5	14.3
AZ-NM-S. NV	30,342	23,530	22.5	29.0	30,331	25,151	17.1	20.6
CA-Mexico-CA [7]	63,168	45,791	27.5	37.9	62,387	48,680	22.0	28.2
Total — US	**857,916**	**648,335**	**24.4**	**32.3**	**859,795**	**693,083**	**19.4**	**24.1**
Canada								
MAPP	6,771	5,045	25.5	34.2	7,026	5,079	27.7	38.3
NPCC	58,110	45,280	22.1	28.3	59,578	46,027	22.7	29.4
Maritime	4,611	2,900	37.1	59.0	4,684	2,778	40.7	68.6
IMO	26,665	22,575	15.3	18.1	27,641	23,384	15.4	18.2
TransÉnergie	26,834	19,805	26.2	35.5	27,253	19,865	27.1	37.2
WECC	20,910	15,301	26.8	36.7	21,220	15,562	26.7	36.4
Total — Can.	**85,791**	**65,626**	**23.5**	**30.7**	**87,824**	**66,668**	**24.1**	**31.7**
Mexico								
WECC-Mexico [8]	2,634	1,634	38.0	61.2	2,634	1,718	34.8	53.3
Total — NERC	**960,680**	**716,527**	**25.4**	**34.1**	**962,575**	**762,418**	**20.8**	**26.3**

Table 3 (cont.): Estimated 2003 Summer Resources, Demands, and Margins

	August				September			
	Available Resources [1] (MW)	Net Internal Demand [2] (MW)	Available Capacity Margin [3] (%)	Available Reserve Margin [4] (%)	Available Resources [1] (MW)	Net Internal Demand [2] (MW)	Available Capacity Margin [3] (%)	Available Reserve Margin [4] (%)
United States								
ECAR [5]	125,786	97,046	22.8	29.6	125,877	87,408	30.6	44.0
ERCOT	77,563	56,945	26.6	36.2	77,563	53,172	31.4	45.9
FRCC	46,459	38,823	16.4	19.7	46,459	37,111	20.1	25.2
MAAC	65,308	53,337	18.3	22.4	65,319	46,994	28.1	39.0
MAIN	63,136	53,544	15.2	17.9	63,307	45,196	28.6	40.1
MAPP	34,755	27,885	19.8	24.6	34,672	25,462	26.6	36.2
NPCC	69,465	56,550	18.6	22.8	68,685	49,424	28.0	39.0
NYISO	37,756	31,430	16.8	20.1	36,977	28,300	23.5	30.7
ISO NEL	31,709	25,120	20.8	26.2	31,708	21,124	33.4	50.1
SERC [6]	177,248	150,411	15.1	17.8	174,859	135,984	22.2	28.6
Entergy	30,418	25,194	17.2	20.7	30,418	22,402	26.4	35.8
Southern	51,422	44,404	13.6	15.8	50,136	39,218	21.8	27.8
TVA	31,884	27,368	14.2	16.5	31,020	25,453	17.9	21.9
VACAR	64,455	53,445	17.1	20.6	64,216	48,911	23.8	31.3
SPP	47,590	38,706	18.7	23.0	47,590	34,593	27.3	37.6
WECC [6]	152,976	117,499	23.2	30.2	151,119	108,114	28.5	39.8
NWPP [7]	48,251	32,732	32.2	47.4	46,859	30,566	34.8	53.3
RMPA	11,531	9,584	16.9	20.3	11,236	9,037	19.6	24.3
AZ-NM-S. NV	30,827	24,923	19.2	23.7	31,322	22,918	26.8	36.7
CA-Mexico-CA [7]	62,367	50,260	19.4	24.1	61,702	45,593	26.1	35.3
Total — US	**860,286**	**690,746**	**19.7**	**24.5**	**855,450**	**623,458**	**27.1**	**37.2**
Canada								
MAPP	6,912	5,251	24.0	31.6	6,823	4,953	27.4	37.8
NPCC	61,205	45,657	25.4	34.1	58,286	44,731	23.3	30.3
Maritime	4,476	2,736	38.9	63.6	4,279	2,925	31.6	46.3
IMO	28,102	23,021	18.1	22.1	26,928	21,254	21.1	26.7
TransÉnergie	28,627	19,900	30.5	43.9	27,079	20,552	24.1	31.8
WECC	21,812	15,513	28.9	40.6	21,370	15,412	27.9	38.7
Total — Can.	**89,929**	**66,421**	**26.1**	**35.4**	**86,479**	**65,096**	**24.7**	**32.8**
Mexico								
WECC-Mexico [8]	2,634	1,754	33.4	50.2	2,634	1,723	34.6	52.9
Total — NERC	**965,014**	**759,885**	**21.3**	**27.0**	**960,094**	**691,221**	**28.0**	**38.9**

Notes to Table 3

[1] Existing available generating capacity, plus new units scheduled for service by the given month, plus the net of firm capacity purchases and sales.

[2] Projected peak-hour demand for the given month, including standby demand, less the sum of direct control load management and interruptible demands. The Regions are not expected to reach their peak demands simultaneously.

[3] The difference between available resources and net internal demand, expressed as a percentage of available resources. This is the capacity available to cover random factors such as forced outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippage. Variations from capacity margins in Regional tables may exist due to differences in reporting methods for purchases and sales.

[4] The difference between available resources and net internal demand, expressed as a percentage of net internal demand. This is the capacity available to cover random factors such as forced outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippage. Some Regions use available reserve margin as one of their standards in assessing adequacy. Available capacity margins are shown in this report for comparison purposes.

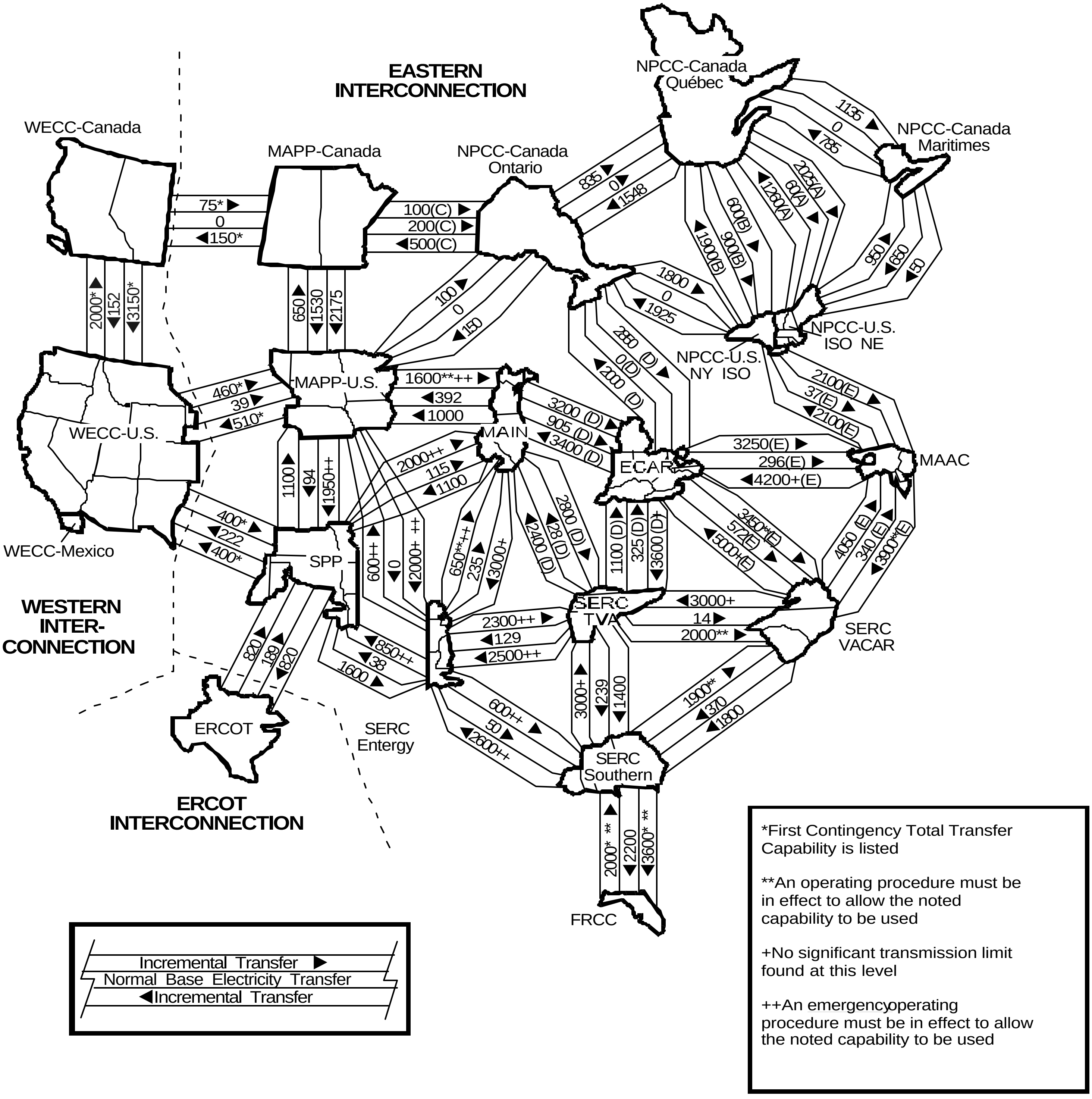
[5] This is the aggregate noncoincident peak demand projection, adjusted for the historical diversity of the ECAR Region.

[6] The sum of the area's resources does not equal the Regional total because portions of the reported area sales and purchases are internal to the Region.

[7] The hydro capability for the Oregon / Washington area of the NWPP is derated by about 1,800 MW from its generation capability to meet biological opinion requirements resulting from the Endangered Species Act. For additional detail on the constraints applied, see the NWPP area narrative in the WECC Region in this report. A 2,500 MW hydro limitation is used for the California ISO for this summer based on hydro capacity experience with runoff conditions and irrigations requirements. Hydro capability for other WECC areas is the generating capability under median hydro conditions.

[8] Only the northern portion of the Baja California Norté Mexico electric system is interconnected with the United States electric system.

Figure 2: Normal Base Electricity Transfers and First Contingency Incremental Transfer Capabilities (Nonsimultaneous), MW



Definitions and Notes to Figure 2

The nonsimultaneous transfer capabilities shown in Figure 2 represent the ability of the transmission network to transfer electricity from one area to another for a single demand and generation pattern. Different patterns of demand and generation cause variations in transfer capabilities on a day-to-day (or hour-to-hour) basis. Therefore, the values on this diagram should be considered as representative, rather than definitive. The values in Figure 2 result from Regional and interregional assessments conducted seasonally. For more information, refer to the interregional studies for this peak demand season.

First Contingency Incremental Transfer Capability (FCITC) is the amount of electricity, incremental above normal base electricity transfers, that can be transferred over the transmission network in a reliable manner, based on the following conditions:

1. With all transmission facilities in service, all facility loadings are within normal ratings and all voltages are within normal limits.
2. The bulk electric system is capable of absorbing the dynamic electric swings and remaining stable following a disturbance resulting in the loss of any single generating unit, transmission circuit, or transformer.
3. After the dynamic swings following a disturbance (resulting in the loss of any single generating unit, transmission circuit, or transformer, but before operator-directed system adjustments are made), all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

First Contingency Total Transfer Capability (FCTTC) is the total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two areas of the interconnected transmission system in a reliable manner based on conditions 1, 2, and 3 in the FCITC definition above.

Specific Diagram Notes

Note A — The base limit for the Phase II tie HVDC facility between ISO NE and TransÉnergie ranges between 1,200 and 1,800 MW, and can be increased when west-to-east transfers in the MAAC Region and the New York Central East interface flows are below their limits.

The expected total transfer capability of 2,085 MW from TransÉnergie to ISO NE is based on 1,800 MW through Phase II, 225 MW through Highgate, and 60 MW through the Stanstead – Derby tie. The expected total transfer capability of 1,200 MW from ISO NE to TransÉnergie is based on 1,200 MW through Phase II, zero MW through Highgate, and zero MW through the Stanstead – Derby tie.

Note B — The FCTTC from TransÉnergie to NYISO is 1,500 MW over the Chateauguay–Massena 765 kV interconnection #7040, on which the power flow is controlled by the HVDC facilities at Chateauguay and radial generation at Beauharnois. This limit is dependent on internal NYISO conditions, particularly voltage profiles in the central New York 345 kV system. The 1,500 MW FCTTC does not include Hydro-Québec resources that can be radially connected to the Niagara Mohawk system.

Note C — An additional 55 MW will be transferred from Manitoba into the IMO (radial generation over the Seven Sisters – Kenora 115 kV circuit #SK1 interconnection).

Note D — Transfers calculated with Allegheny Power classically dispatched as part of ECAR.

Note E — Transfers calculated with Allegheny Power dispatched as part of the PJM market in MAAC.

Regional Self-Assessments

Summary tables are provided in each Regional assessment to provide a quick reference of projected demand and resources for the coming summer. The following definitions are used in the tables:

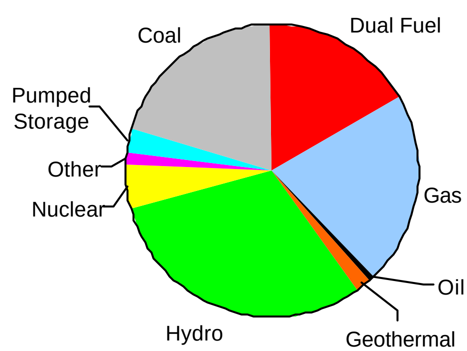
Projected Internal Demand	Internal demand plus standby demand (monthly coincident)
Interruptible Demand & DSM	Interruptible demand and direct-control demand-side management
Projected Net Internal Demand	Projected internal demand less interruptible demand and direct control load management (monthly coincident)
Last Summer's Peak Demand	Last summer's actual peak demand
% Change	Change in projected internal demand compared to last summer's actual peak demand
All-time Summer Peak Demand	All-time summer peak demand
Net Operable Capacity	Installed capacity less inoperable capacity
Projected Purchases	Total projected firm capacity purchases
Projected Sales	Total projected firm capacity sales (adjusted for joint-ownership transfers)
Adjustment to Purchases and Sales	Adjustment for transfers of capacity associated with remotely located, totally owned or jointly owned, generating units are included in capacity purchases or sales
Net Capacity Resources	Net operable capacity plus projected purchases less projected sales
% Capacity Margin	Net capacity resources less projected net internal demand divided by net capacity resources, expressed as a percent
% Reserve Margin	Net capacity resources less projected net internal demand divided by net internal demand, expressed as a percent

Monthly noncoincident projections are used in these tables and the selected month has the highest projected net internal demand for the season. Historical demands may be either seasonal or monthly noncoincident values.

Capacity Fuel Mix

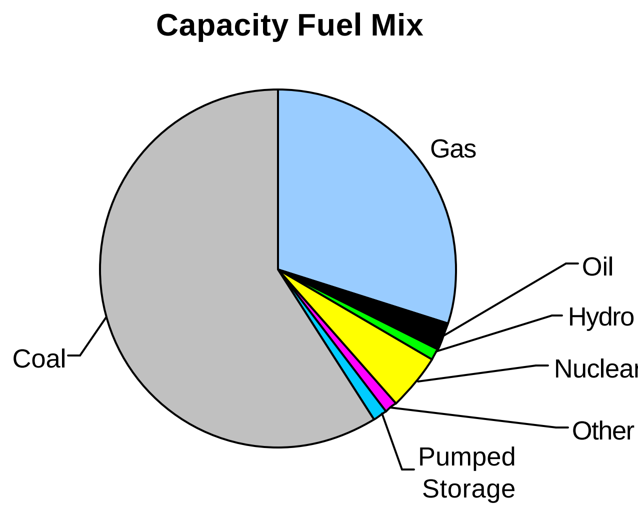
The Regional capacity fuel mix charts show each Region's relative dependence on various fuels for their reported generation capacity. These are based on the most recent data available in NERC's *Electricity Supply and Demand* database.

Capacity Fuel Mix



ECAR

Projected Internal Demand	100,714 MW
Interruptible Demand & DSM	2,956 MW
Projected Net Internal Demand	97,758 MW
Last Summer's Peak Demand	101,150 MW
Change	(0.4)%
All-Time Summer Peak Demand	101,346 MW
Net Operable Capacity	123,193 MW
Projected Purchases	3,557 MW
Projected Sales	1,015 MW
Adj. to Purchases & Sales	—
Net Capacity Resources	125,735 MW
Capacity Margin	22.3 %
Reserve Margin	28.6 %



Demand

ECAR's total internal summer demand forecast is 100,714 MW. This is 436 MW (0.4%) lower than the 2001 record peak demand of 101,346 MW.

Resources

ECAR's total connected capacity to serve demand within ECAR is projected to be 123,502 MW (net seasonal capability), which is 3,120 MW higher than last summer. The capacity margin is projected to be 22.3%, compared to 21.5% expected last summer. Based on the projections of connected demand, generation, and interchange power contracts, there is a low probability of exceeding the margin available for contingencies (capacity resources minus the sum of peak demand, known maintenance, and operating reserve requirements) this summer. ECAR projects that there is less than a 1% likelihood that it will rely on supplemental capacity resources at the time of the summer peak demand. Supplemental capacity resources may include curtailment of contractually interruptible loads, curtailment of demand-side management loads, and additional purchased power. ECAR does not anticipate any reliance on supplemental resources for average daily conditions this summer. Adverse conditions, such as the delay of scheduled capacity additions, abnormally hot, humid weather, or low generator availability, coupled with an inability to purchase additional power, could make it necessary to curtail demand beyond contractually interruptible loads and demand-side management. However, these adverse conditions are not expected to occur.

Transmission

There is a continuing need for the reliability coordinators, transmission planners, and operators to communicate and coordinate their actions to preserve the continued reliability of the ECAR system. It is anticipated that the ECAR transmission system could become constrained as a result of unit unavailability and/or economic transactions that have historically resulted in large unanticipated power flows within and through ECAR. If these conditions occur again this summer, local operating procedures, as well as the NERC Transmission Loading Relief procedure (TLR), will need to be invoked in order to maintain transmission system security. As long as transmission limitations are identified and available operating procedures are implemented when required, no cascading events are anticipated.

Very few significant transmission facility changes are expected for this summer as compared to last summer; however, several ECAR members have added transformer capacity since last summer. Facilities that have experienced TLRs in the past continue to show up as constraints in this assessment. Depending upon real time conditions, it is likely that many of these facilities will experience TLRs again this summer. In general, using total import capability as a measure, the ECAR transmission system will be more constrained this summer as compared to last summer.

The most significant transmission facility and operational issues regarding the system include:

- The Michigan–Ontario interface is susceptible to large parallel flows and TLR curtailments. The Michigan–Ontario Phase Angle Regulator (PAR) project will impact flows on this interface. This project was originally scheduled to be completely in service by the 2003 summer season. However, given the recent failure of the B3N PAR and the delay of the installation of the final PAR at Lambton, the Michigan–Ontario interface is not expected to be completely controlled by phase shifters during this summer.
- AEP will continue to use the Special Transmission Emergency Procedures (STEP) to maximize the loadability of the critical Kanawha River – Matt Funk 345 kV (AEP) circuit and reduce the reliability risks of potential widespread power interruptions in the southeastern portion of ECAR.
- Potential voltage limitations have been identified through past operating experience or other ECAR assessments in the Louisville Gas & Electric (LGEE) area. The analysis indicates that voltages at LGEE's Brown North 138 kV bus are expected to be significantly better compared to the 2002 assessment results, particularly for the scenario in which none of the combustion turbines at LGEE's Brown plant or EKPC's J.K. Smith plant are dispatched. The improvement in voltage levels is primarily due to the addition of 160 Mvar of capacitors on LGEE's 69 kV system in the central Kentucky area since the summer of 2002.

Operations

As a result of regional transmission organization (RTO) activity, ECAR has coordinated the transition process that has realigned the control areas and the reliability authorities responsible for monitoring system operations in the ECAR Region. All ECAR control areas have made the transition to the reliability coordinators associated with the Midwest ISO, PJM, or TVA. These are the reliability coordinators that will monitor power flows and control critical transmission interface loadings throughout ECAR.

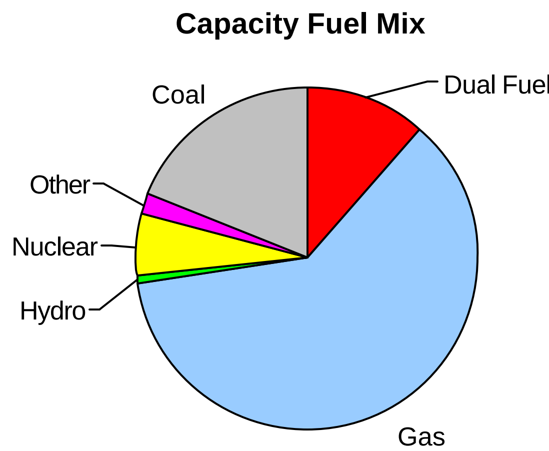
In addition to the NERC TLR procedure, other operating procedures are available to maintain reliable system operations. These include:

- The Voltage Coordination Plan 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.
- A multiregional agreement involving control areas around Lake Erie to use generation redispatch to mitigate emergency TLR procedures and curtailments in situations where the affected system(s) is about to curtail firm demand. The Lake Erie Security Process Working Group has been asked to develop an overall strategy for coordinated operation of all control devices, including the new PARs on the Michigan–Ontario interface. In the interim, MISO and the IMO indicate that they will direct the settings on the PARs to assist neighboring systems that are experiencing emergency conditions.
- Operating procedures will be used by the reliability coordinators to reduce the risks of potential widespread interruptions until AEP's approved Wyoming–Jacksons Ferry 765 kV line is completed.

Additional details on ECAR's demand and capacity assessment (report 03-GRP-33) is available on the ECAR website (www.ecar.org). Detailed information on the transmission assessment (report 03-TSPP-3) is available by contacting the ECAR office.

ERCOT

Projected Internal Demand	57,664 MW
Interruptible Demand & DSM	719 MW
Projected Net Internal Demand	56,945 MW
Last Summer's Peak Demand	56,233 MW
Change	2.5 %
All-Time Summer Peak Demand	57,606 MW
Net Operable Capacity	77,644 MW
Projected Purchases	110 MW
Projected Sales	191 MW
Adj. to Purchases & Sales	—
Net Capacity Resources	77,563 MW
Capacity Margin	26.6 %
Reserve Margin	36.2 %



Demand

The actual peak demand for 2002 was 56,233 MW. This exceeded the 2001 peak demand of 54,862 MW by 2.5%. However, the all-time peak demand in ERCOT remains at 57,606 MW, which was experienced in 2000. The 2003 summer peak demand forecast of 57,664 MW was made using weather-normalized historic growth rates and also reflects an increase of 2.5% from the 2002 actual peak demand.

Resources

The projected capacity margin for 2003 at peak is 26.6%, which is significantly above the newly adopted Regional requirement of 11%. The actual capacity margin for 2002 was 26.3%. Approximately 3,600 MW of new generation capacity is expected to commence commercial operation before and during the summer of 2003. This will result in a net increase in operable capacity of 1,963 MW from the summer of 2002 after taking into account existing generation that has been taken out of service in the past year. All but 200 MW of the new generation capacity can be considered merchant capacity.

Entities in ERCOT have contracts that enable them to purchase 110 MW from SPP; however, these purchases are not necessary to meet the demand requirements. ERCOT has 191 MW of firm sales to SPP.

There are no anticipated fuel supply problems or hydro concerns for the upcoming summer. Hydro accounts for less than 1% of ERCOT generation capacity.

Transmission

The most frequently encountered ERCOT transmission constraints this summer are expected to be:

- South Texas–North Texas
- West Texas–North Texas
- South Texas–Houston
- Rio Pecos–Crane
- Graham Plant–West Texas
- Dallas–Fort Worth (DFW) Area Import
- North Edinburg–McColl Road
- La Palma–Rio Hondo
- Laredo Area Import
- North Edinburg–Rio Hondo
- Duke Plant–South Edinburg
- Morgan Plant–the East

ERCOT has supported and recommended a number of major projects that will help mitigate these constraints. The following projects and the constraints (in parenthesis) they are designed to mitigate are currently under development by transmission service providers and expected to be in service this summer:

- Morgan Creek–Twin Buttes–Red Creek–Comanche Switch 345 kV line (West Texas–North Texas)
- Watermill–Cedar Hill 345 kV line (DFW Import)
- Forney–Centerville 345 kV line (DFW Import)
- Watermill–Tricorner 345 kV line (DFW Import)
- Several 345/138 kV autotransformers (DFW Import)

Over 800 MW of wind generation is now operating in West Texas to the south of Odessa, a transmission-limited area. This has caused frequent wind generation curtailments due to local constraints (Rio Pecos–Crane) during periods of high wind generation.

Interregional transmission transfer capability is limited to two DC ties with SPP that have a total capability of 820 MW. ERCOT does not expect to require external assistance from those ties to meet the projected summer peak.

Operations

A new 345/138 autotransformer was placed in service in the Dallas-Ft. Worth area; five more are scheduled to go into service for this summer. This is expected to considerably reduce local transmission constraint management in the area, which has been a significant challenge in past summers.

Current constraints associated with frayed conductors on two 345 kV lines to the Rio Grande Valley are expected to be repaired before peak summer load conditions.

During peak load conditions, ERCOT must have generation running at specific locations to remain secure without risk of post-contingency local load shedding. ERCOT has signed Reliability Must Run contracts this summer with several critical generating units that would have otherwise been taken out of service in some of these locations.

There are reports that the South Texas Project Unit 1, a 1,250 MW nuclear unit, may not be available for most of the summer. Some evidence of pressure vessel leakage was found during the unit's refueling outage this spring that will require further investigation. If the unit is unavailable, ERCOT does not expect it will result in any significant resource adequacy or transmission congestion management problems this summer.

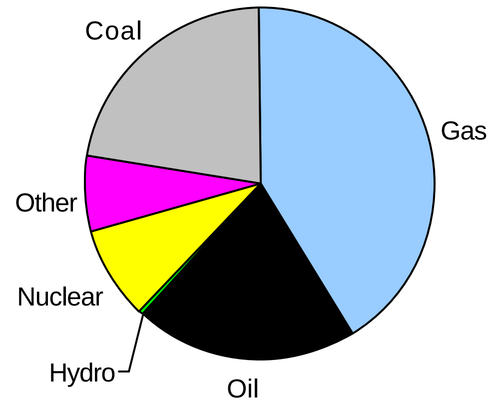
Widespread gas curtailments to electric generators throughout the Region affected the energy market during several days of cold weather in late February. On February 25, 2003, ERCOT implemented the Emergency Electric Curtailment Plan (EECP) - Step 1 to address a potential market shortage of electricity. In response to the EECP, the market brought on sufficient capacity to avoid implementing further steps of the EECP and no interruptible or firm load shedding was necessary. Gas curtailments are more likely to occur in the winter and are not anticipated for the upcoming summer season. There are no anticipated environmental or regulatory restrictions for summer 2003 that would significantly limit available generation.

FRCC

Projected Internal Demand	41,618 MW
Interruptible Demand & DSM	2,795 MW
Projected Net Internal Demand	38,823 MW
Last Summer's Peak Demand	40,260 MW
Change	3.4 %
All-Time Summer Peak Demand	40,260 MW
Net Operable Capacity	44,869 MW
Projected Purchases	1,590 MW
Projected Sales	—
Adj. to Purchases & Sales	—
Net Capacity Resources	46,459 MW
Capacity Margin	16.4 %
Reserve Margin [1]	19.7 %

[1] FRCC uses Reserve Margin, not Capacity Margin, as its standard to assess adequacy.

Capacity Fuel Mix



Demand

FRCC expects to reach its forecast 2003 summer firm peak demand of 38,823 MW in August. This projection is consistent with historical, weather-normalized FRCC demand growth. Demand in Florida is typically at a constant level through the summer period. The forecast includes demand reductions due to the use of load management and interruptible demand capabilities. Demand reduction capabilities are estimated to be 2,795 MW.

Resources

The net capacity resources within FRCC, which include 1,590 MW of external long-term firm non-recallable purchases, are expected to adequately meet the forecasted firm peak demand with a 20% reserve margin. Merchant plant capacity under firm contract has been included in FRCC's capacity resource calculation. About 850 MW of merchant capacity not under firm contract is not included in those calculations for this summer.

No scheduled maintenance outages of any significance are planned for the summer. Since January 1, 2003, an additional 1,497 MW of net generation will have been added prior to the 2003 summer peak. The majority of this new net generation is due to the re-powering of existing units.

FRCC has examined the fuel supply and found that it is adequate for the Region.

Transmission

The FRCC bulk transmission system is expected to perform adequately over various system operating conditions. The results of the *2003 Summer Transmission Study*, which evaluated different operating scenarios, indicate that any thermal overloads or voltage violations can be managed successfully by operator intervention. Such interventions include generation redispatch, system sectionalizing, reactive device control, and transformer tap adjustments.

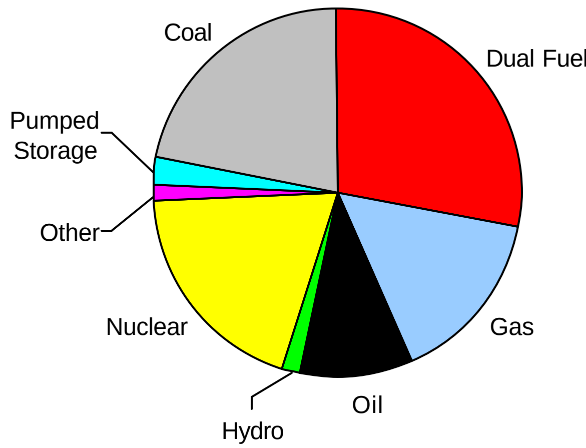
Operations

FRCC does not foresee any reliability issues for 2003 summer.

MAAC

Projected Internal Demand	56,257 MW
Interruptible Demand & DSM	1,273 MW
Projected Net Internal Demand	54,984 MW
Last Summer's Peak Demand	55,569 MW
Change	1.2 %
All-Time Summer Peak Demand	55,569 MW
Net Operable Capacity	64,820 MW
Projected Purchases	488 MW
Projected Sales	—
Adj. to & Purchases & Sales	—
Net Capacity Resources	65,308 MW
Capacity Margin	15.8 %
Reserve Margin	18.8 %

Capacity Fuel Mix



Demand

The MAAC 2003 summer forecast net peak demand is 54,984 MW. This forecast includes the effects of interruptible demand and load management capabilities, which are estimated to be 1,273 MW. The forecast peak assumes normal summer weather conditions. This forecast is 585 MW lower than the actual MAAC all-time summer peak of 55,569 MW that occurred on August 14, 2002.

Resources

Between June 1, 2002 and June 1, 2003, summer generating capacity is expected to increase by a net of 3,358 MW to 64,820 MW, with 1,952 MW already in service. All nuclear units should be in service and at full capacity (13,030 MW) at the time of the peak. MAAC also has 488 MW of external capacity resources under contract through the summer peak period. With the planned new generation, existing internal generation, and external capacity resources included, the capacity margin is forecasted to be 15.8% at the time of the forecasted peak, which equates to an 18.8% reserve margin.

MAAC expects to have sufficient generating capacity to serve the 2003 forecast summer peak demand. When the Region served its all-time summer peak on August 14, 2002, no emergency procedures were implemented.

MAAC has a net of 698 MW of long-term firm transmission service contracts in place for energy sales out of the Region through the summer peak period. Presently, these transactions are not capacity-backed and can be curtailed in the event of a PJM Capacity Emergency. Historically, approximately 1,200 MW of capacity has been transferred out of MAAC on peak summer days and could, therefore, decrease the capacity margin by 1.6%.

Transmission

The bulk transmission system is expected to perform adequately over various system conditions.

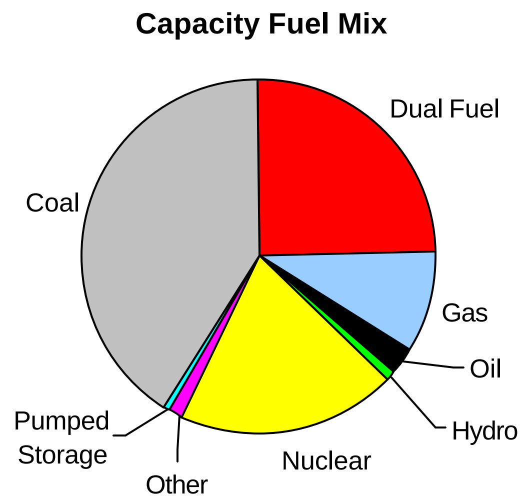
Operations

PJM, for the MAAC Region, is well prepared for operating emergencies should they occur. PJM conducts regular drills to ensure that they are prepared in the event of an extremely hot summer.

MAIN

Projected Internal Demand	57,312 MW
Interruptible Demand & DSM	3,209 MW
Projected Net Internal Demand	54,103 MW
Last Summer's Peak Demand	55,300 MW
Change	3.6 %
All-Time Summer Peak Demand	55,977 MW
Net Operable Capacity	63,908 MW
Projected Purchases	1,367 MW
Projected Sales	2,148 MW
Adj. to Purchases & Sales	—
Net Capacity Resources	63,127 MW
Capacity Margin	14.3 %
Reserve Margin [1]	16.7 %

[1] MAIN uses Reserve Margin, not Capacity Margin, as its standard to assess adequacy.



Demand

MAIN's total internal noncoincident peak demand forecast for summer 2003 is 57,312 MW, assuming normal weather conditions. This is 1,335 MW (2.4%) higher than the last summer's peak demand.

Resources

MAIN's forecasted reserve margin based on capacity committed to serve load is 16.7%, which is judged to be adequate to supply forecasted summer demand. MAIN recommends a minimum 15% reserve margin for short-term planning purposes. Last year, MAIN forecasted a reserve margin of 15.5% in the *2002 Summer Assessment.* Subsequently, the May 2002 annual detailed audit forecasted a 2002 summer reserve margin of 17.3%.

About 1,200 MW of new generation is expected to come on line before or during the summer. Since last summer, 2,000 MW of generation has been retired, mothballed, or temporarily removed from service and will not be available for the summer period. The forecasted reserve margin of 16.7% does not include about 4,700 MW of uncommitted generating resources within MAIN. For the 2003 summer, the Region is expected to be a net firm exporter of 781 MW.

Neither fuel problems nor limitations of hydro resources are expected. Hydro resources account for less than 2% of MAIN's installed capacity.

Transmission

In general, the transmission system is expected to perform reliably under a wide range of conditions. Import capabilities into MAIN from surrounding Regions are generally considered adequate. The table below compares MAIN's import FCTTCs for the summers of 2002 and 2003. The FCTTC values in the table below were developed to help assess MAIN's supply reliability. These values are not the same as the available transfer capabilities (ATCs) posted on an OASIS node. The notes associated with *Figure 2* of this report are also applicable to the table below.

Table MAIN 1: MAIN Import First Contingency Total Transfer Capabilities (FCTTC) (MW)*

	2003	2002
ECAR	2,500	4,000
TVA	2,400	2,100
SERC West *	900	0
SPP *	2,100	2,200
MAPP *	1,200	1,500

*Operating guides used as required

Most of the regional and subregional FCTTCs are judged to be adequate. The remaining few FCTTCs listed below are judged to be marginally adequate:

- MAIN imports from SERC West
- Southern MAIN, imports from Entergy
- Ameren imports from IP and Entergy
- Import capability into ALTW
- Import capability into Wisconsin. The import capability into Wisconsin – Upper Michigan is dependent upon Dairyland Power Cooperative's installation of a transformer near Galena, IL. This 44 MVA, 161/ 69 kV portable transformer is planned to be in service by June, and is expected to remain in service for the duration of the summer.

A summary of transmission improvements since last summer is included in Appendix 2. A complete listing of all transmission improvements since summer 2002 and transfer capabilities are available in the *2003 MAIN Summer Transmission Assessment Study*.

Operations

MAIN does not anticipate any major unit outages for the summer period.

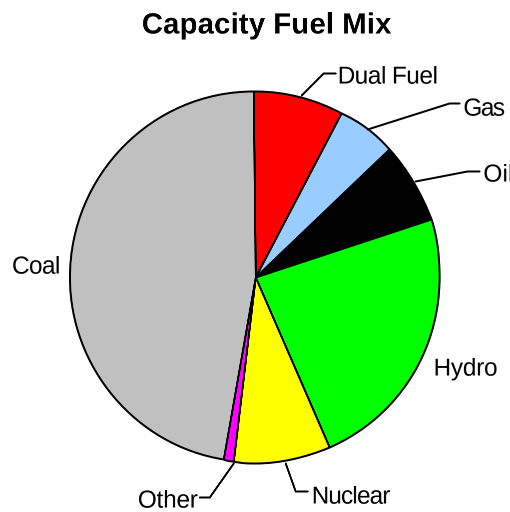
Local environmental restrictions on certain generation units are not expected to significantly impact availability during peak load conditions. However, many coal-fired units have installed selective catalytic reduction devices for NO_x control. Unexpected problems with these new devices may restrict unit availabilities during the summer season.

Historically constrained interfaces such as MAPP–MAIN continue to require special operating attention and procedures to maintain reliable operation. American Transmission Company has proposed a 345 kV line between Minnesota and Wisconsin that will help to relieve constraints associated with imports into Wisconsin, and MAIN imports from MAPP. This proposal is under re-examination by Wisconsin regulators. However, this reinforcement is not expected to be complete prior to summer 2007.

Several lines in southern MAIN have experienced heavy loadings requiring TLR in past years. While some system reinforcements have been made, similar power transfer conditions would require close monitoring of system facilities and close coordination among all parties on a continued basis. In MAIN, there were 221 TLRs level 3 and above between June and August 2002. Until sufficient transmission reinforcements are in place, similar levels of TLRs are expected. Historical TLR data can be found at: *http://www.nerc.com/~filez/Logs/index.html*.

MAPP

Projected Internal Demand	35,168 MW
Interruptible Demand & DSM	1,596 MW
Projected Net Internal Demand	33,572 MW
Last Summer's Peak Demand	33,830 MW
Change	4.0 %
All-Time Summer Peak Demand	34,896 MW
Net Operable Capacity	41,425 MW
Projected Purchases	6,130 MW
Projected Sales	5,710 MW
Adj. to Purchases & Sales	6 MW
Net Capacity Resources	41,851 MW
Capacity Margin	19.8%
Reserve Margin	24.7%



Demand

The expected summer noncoincident peak demand in combined MAPP-US and MAPP-Canada is 35,168 MW. That is 4.8% above last summer's peak forecast of 33,556 MW and 4.0% above last summer's actual peak demand of 33,830 MW. The load forecast assumes average weather conditions.

Resources

The projected MAPP capacity margin is 19.8%. The MAPP Reserve Capacity Obligation requirement is 15%, which is equivalent to a 13.04% capacity margin requirement. This also compares to the 2002 summer capacity margin of 19.7%. Capacity additions for this summer are 910 MW consisting of gas turbines and internal combustion engines.

There is a projected net transaction balance between MAPP and the other Regions. There are 774 MW of firm purchases planned from outside of MAPP, and 776 MW of firm sales planned to others outside the Region.

There are no known fuel limitations anticipated in the Region for this summer.

Transmission

MAPP continues to monitor the 19 transmission constraints within the Region. These constraints can limit MAPP imports and exports. Detailed descriptions of the constraints can be found on the MAPP OASIS node.

The reliability of the transmission system is currently measured by studying its historical performance and determining the thermal, voltage, and dynamic stability limitations. MAPP conducts several steady-state studies annually that provide an indication of transmission system strength and the necessary data to facilitate analyses of the MAPP network. In addition, MAPP is placing more emphasis on voltage security/stability analysis. Improvements in voltage study techniques are being implemented to ensure safe operating margins. In general, the MAPP transmission system is judged to be adequate to meet firm obligations of the member systems for this coming season.

The following discussion is based on the *MAPP-MAIN-SPP (MMS) 2003 Summer Study*.

The MAPP 2003 summer export to MAIN FCITC is 1,600 MW limited by the Eau Claire–Arpin 345 kV Limit with the availability of the Arpin Area Operating Guides and the Taconite Harbor Emergency Operating Guide.

Without the availability of these guides, the MAPP–MAIN FCITC would be 200 MW. The 400 MW decrease from 2002 in MAPP–MAIN FCITC can be attributed to a decreased flow limit being enforced on the Eau Claire – Arpin 345 kV line.

The MAPP 2003 summer import FCITC from MAIN is 1,000 MW, limited by the Poweshiek–Reasnor 161 kV line for the outage of the Bondurant–Montezuma 345 kV line. The FCITC of 1,000 MW is 50 MW less than that reported in the 2002 summer study, attributed primarily to base flow differences between base case models.

The MAPP 2003 summer import FCITC from SPP is 1,100 MW, limited by the St. Joe–Midway 161 kV line for the outage of the Fairport–Nodaway 161 kV line. No operating guides were required to reach this level. There is a 300 MW increase from the 2002 summer FCITC due to base flow differences between the base case models.

The MAPP 2003 summer export to SPP FCITC is 1,950 MW, limited by the Fort Smith 500/161 kV transformer for the outage of Fort Smith 345/161 kV transformer with the Arpin Area Operating Guides and the Taconite Harbor Emergency Operating Guide available. Without the availability of these guides, the MAPP to SPP FCITC would be 350 MW.

Operations

No operational issues are expected by the Region for the summer.

Subregions

Northern MAPP

No significant operational issues are expected this summer for the northern MAPP region. The standing guides have proven to effectively deal with the system conditions throughout the year.

The Harvey–Glenboro 230 kV line was energized during the 2002/03 winter season. This line improves system reliability in the region and increases the transfer capability between Canada and the United States. Updated comprehensive summer operating studies will be completed for the Manitoba-US interfaces and the North Dakota export interface due to the system improvements.

A number of bulk transmission outages are scheduled in northern MAPP for maintenance; however, no operating problems are expected. Temporary operating guides will be developed as necessary.

Iowa

Iowa is not expected to face any major operational issues this summer. The flow pattern that Iowa experienced during summer 2002, consisting of significant transfers from east-to-west, is expected to continue during summer 2003, but an addition of 350 MW of generation at Greater Des Moines Energy Center will enable better control of potential operational problems.

Five new Alliant Energy flowgates have been added to the MAPP Schedule F evaluation process to coordinate seams issues between MAPP and MISO. These flowgates will be used to protect 161 kV lines from post-contingency overloading during periods characterized by heavy south-to-north transfers.

As discussed in the MAIN section of this report, the Lore–Turkey River 161 kV line is expected to require a number of TLRs related to heavy regional south-to-north flows. There is a standing operating guide that addresses operational problems regarding the Lore–Turkey River line. This operational situation between MAPP and MISO includes the opening of underlying 69 kV circuits from Illinois into Wisconsin under post contingency situations, and the effect of outages of generation north of Lore. This situation also has direct bearing on the import capability of the WUMS subregion of MAIN.

Nebraska

Conditions on the Nebraska constrained interfaces are expected to be identical to last summer. Existing operating guides have proven to be effective in dealing with the issues at each constrained interface.

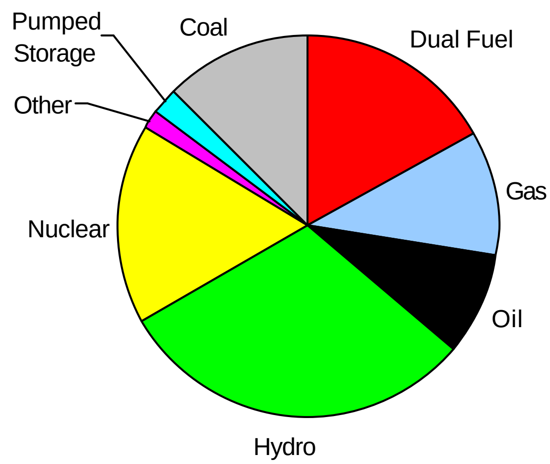
Nebraska has no constrained import interfaces for this summer, but does have five constrained export interfaces. During summer peak loading periods, the two most limiting export interfaces, Cooper South and Western Nebraska–Western Kansas, will be monitored closely. During peak periods with heavy exports to the south, operating guides for the Western Nebraska–Western Kansas interface are used to maintain acceptable voltage levels in western Nebraska.

West-to-east transfers across Nebraska are mainly impacted by western Nebraska generation resources and the Sidney and Stegall DC ties. In the last several years, there has been a large increase in the number of days that the DC ties transferred power from east to west. Such transfers reduce the west-to-east flows that are normally seen across Nebraska. The recent lower levels of WAPA hydro generation have also impacted the north-to-south flows across the Nebraska system.

NPCC

Projected Internal Demand	103,526 MW
Interruptible Demand & DSM	—
Projected Net Internal Demand	103,526 MW
Last Summer's Peak Demand	105,166 MW
Change	(1.6)%
All-Time Summer Peak Demand	105,166 MW
Net Operable Capacity	138,687 MW
Projected Purchases	4,506 MW
Projected Sales	2,120 MW
Adj. to Purchases & Sales	(106)MW
Net Capacity Resources	140,967 MW
Capacity Margin	26.6 %
Reserve Margin	36.2 %

Capacity Fuel Mix



Demand

The projected summer coincident peak demand for the combined NPCC US and NPCC Canada is 103,013 MW, 2.8% above last summer's coincident peak forecast of 100,234 MW and 0.6% below last summer's actual coincident peak demand of 103,606 MW. Load forecasts assume average weather conditions.

Resources

ISO New England and the New York ISO expect sufficient resources to be available to meet projected demands during 2003 summer. New generation additions will help to meet the summer demand. Between March and September, ISO New England expects about 3,500 MW of generation additions. The New York ISO expects up to 1,178 MW of capacity additions for the summer, of which 98 MW is located in the Long Island load zone.

Ontario expects to have adequate resources available to meet forecast demand and energy requirements during the summer peak period. This forecast considers the planned return to service of about 2,000 MW of nuclear generation from long-term outage. If the return to service of this generation is delayed, then external support may be required during high demand conditions or if generator forced outage rates are higher than forecast in order to meet peak demands.

The other NPCC Canadian Subregions, Québec and the Maritimes (the provinces of New Brunswick, Nova Scotia and Prince Edward Island), are predominately winter peaking control areas; adequate resources are expected to be available to serve the forecast summer peak demand and meet operating reserve requirements.

Transmission

In southwestern Connecticut, reliability problems are possible due to transmission constraints into and within this vicinity. The New England Subregion discussion below indicates the specific measures being taken to meet the reliability needs of the area.

Operations

No operational issues are expected by the Region for the summer.

Subregions

Maritimes

Based on the Maritimes Area 2003 demand forecast, a peak load of 3,474 MW is predicted to occur for the summer period during the week beginning June 29, 2003. The actual peak for summer 2002 was 3,494 MW in August (noncoincident). Since the Maritimes Area is winter-peaking, forecasted peaks for the shoulder months of May and September are normally higher than the summer period. For the week beginning May 4, 2003, the predicted peak is 3,720 MW and for the week beginning September 28, 2003, the predicted peak is 3,511 MW.

The coincident peak load experienced by the Maritimes Area during the May–September period was 3,731 MW, which was approximately 184 MW (5.2%) higher than last year's forecast of 3,547 MW. This is due to the peak occurring in May while experiencing below normal temperatures. This resulted in a greater electric heating load than would normally be the case.

When allowances for unplanned outages (based on a discreet MW value representing a typical forced outage) are considered, the Maritimes Area is projecting more than adequate capacity margins for this summer. Net margins are comparable to summer 2002, ranging from 19% to 42% from May through September, compared to the Regional requirement of 20% of forecasted demand.

The fuel supply in the Maritimes Area is diverse and includes nuclear, natural gas, coal, oil (both light and residual), orimulsion, hydro, tidal, municipal waste, and wood. The area is not anticipating any fuel supply problems impacting generation. Units that have been converted to the orimulsion fuel retain their full capability on oil. For summer 2003, there may be occasions when some units are required to be derated in order to meet federal and provincial environmental regulations. However, these are expected to be infrequent and of short duration. Normal hydro conditions are forecasted for this summer.

There have been no major additions to the bulk transmission system. Interconnection capability remains unchanged and is expected to deliver up to 700 MW to New England and up to 700 MW to Québec. Further, there are no planned merchant capacity additions anticipated this summer.

ISO New England (ISO NE)

The ISO New England 2003 summer peak demand forecast (Net Internal Demand) is 25,120 MW. This projected peak demand is 920 MW (3.8%) greater than the 2002 summer peak demand forecast of 24,200 MW. The summer 2003 peak forecast is 228 MW (0.9%) lower than last year's actual and all-time summer peak of 25,348 MW, which occurred on August 14, 2002. New England is forecasting that available resources will be sufficient to meet the demand forecast for the summer, as well as the shoulder months of May and October.

While it is projected that operable capacity is expected to be surplus for New England, southwestern Connecticut is expected to face reliability problems due to transmission constraints into and within that region. To meet critical near-term electric system reliability needs, Connecticut Light and Power Company has implemented an emergency plan for June through September that includes:

- Issuing a Request for Proposal (RFP) for the installation of up to 80 MW of temporary, mobile generation, seeking clean-burning natural gas-powered generation to address reliability needs this summer;
- Installing voltage stabilization and performance equipment to maximize transmission import capabilities into southwestern Connecticut; and
- Aggressively supporting and participating in ISO NE-administered demand side management programs that could potentially reduce this summer's peak load by up to 20 MW in southwestern Connecticut.

Net operable capacity resources of 30,818 MW (August) from ISO NE participants and non-participants include 2,900 MW from new generation not yet in service. Since the in-service date of these new units will impact the summer capacity situation, ISO NE closely monitors the construction and commissioning progress of these new generators. The total amount of known external capacity purchases from control areas outside of New England is approximately 900 MW. This includes 280 MW of ISO NE Participant Entitlement Contracts from Hydro-Québec, 484 MW from the Maritimes and 127 MW from New York. It is likely that additional capacity backed contracts for the summer period will be initiated before June 1, 2003.

ISO NE projects that there may be instances when it will not have sufficient operable capacity within the control area under periods of higher-than-projected peak demands and/or higher-than-anticipated high levels of generating unit forced outages. The ISO would invoke operating procedures to mitigate any such short-term operable capacity deficiencies. ISO NE's Operating Procedure No. 4 (OP-4) Action During a Capacity Deficiency includes: purchasing emergency energy from the interconnected grid, interrupting interruptible load customers, and implementing voltage reductions in the event of a capacity shortage. This procedure would provide load or capacity relief varying between 1,700 MW to 2,700 MW, depending on system conditions at the time.

Load relief from operating procedures is also considered a resource for meeting the ISO NE Resource Planning Reliability Criterion of 1-day-in-10-years disconnection of non-interruptible customers. The amount of load relief obtainable from OP-4 has not been reflected in the available resources reported above. ISO NE does not expect to implement Operating Procedure No. 7–Action in an Emergency (OP-7), which is to be followed in the event of an operating emergency involving unusually low frequency, equipment overload, or unacceptable voltage levels in an isolated or widespread area of New England.

In early April of 2003, the Plattsburgh Phase Angle Regulator (PAR) failed and is not expected to be operational again until late in the summer period. In order to protect the reliability of the Vermont area, ISO NE may limit transfers from New York into New England. Also, ISO NE and other stakeholders have implemented the Plattsburgh PAR Bypass Procedure which specifies actions that can be taken to ensure reliability while the PAR is bypassed, including redispatch of generation, limitation of transfers, and the insertion of series reactors.

The following transmission upgrades are expected to be implemented during or prior to the summer:

- The installation of one 345/115 kV transformer at the Canal substation along with four additional circuit breakers to improve transmission reliability to the Cape Cod area;
- Additional circuit breakers at Coolidge and West Rutland substations, along with the addition of a 345/115 kV transformer at the West Rutland substation to improve reliability to the northwest Vermont region;
- Re-energizing the Coolidge–West Rutland line at 345 kV will also improve the reliability to northwest Vermont;
- In order to increase reliability within the Boston area, the towers on the West Medway–Waltham 230 kV line will be modified to improve clearance and alleviate sag limitations.

New York ISO (NYISO)

The summer 2003 forecast peak for NYISO is 31,430 MW, which is 955 MW higher than summer 2002 forecast of 30,475 MW and 1.4% higher than the all-time peak of 30,982 MW that occurred on August 9, 2001. For peak load normalization, the NYISO uses a temperature-humidity index (THI) value of 81.31 degrees. At forecast load levels, a one-degree increase in the THI will result in approximately 500 MW of additional load.

NYISO conducts semiannual and monthly installed capability (ICAP) auctions. Based on the forecast load for 2003, the ICAP requirement is 37,087 MW based on the 18% installed reserve margin requirement. When allowances are taken for unplanned outages (based on historical performance of 10.2% unavailable capacity), the net available resources will be 33,230 MW, which will be sufficient to meet the NYISO load and operating reserve requirement during the peak load hours.

If necessary, NYISO can also rely on approximately 1,100 MW of load relief from emergency procedures that include internal load curtailment by the transmission owners, public appeals and 5% system wide voltage reductions. Participation in the Emergency Demand Response Program represents an additional 700 MW available from the market.

Resource additions totaling 1,229 MW are expected to be available during the summer. Of this, 1,080 MW represents a new natural gas-fired combined-cycle generating station located near Athens, New York (approximately 110 miles from New York City). The remaining resource additions are combustion turbines in the Long Island load zone.

Supply adequacy for the New York City/Long Island areas will be tight again this year. However, the New York City load zone has acquired 118 MW of ICAP Special Case Resources to ensure that it meets the New York State mandated in-city resource requirement.

Last summer, there was concern that impending drought conditions might cause water use restrictions that could impact generator availability or capability. In late autumn 2002 and continuing into 2003, precipitation levels had returned to normal, and snowpack at the end of the winter was above normal levels in the watershed areas. Should precipitation levels continue near normal through the spring, water use restrictions are not likely and are not expected to affect resource availability or capability.

Ontario

Ontario's forecast summer peak demand is 23,684 MW based on normal weather. This is less than the all-time record summer peak demand of 25,414 MW, which occurred on August 13, 2002. There are no firm sales projected for the 2003 summer.

Ontario could be heavily dependent on imports to serve its requirements if unexpected hot weather occurs in May and June before the scheduled restart of two of three nuclear units from long-term outage. If that generating capacity (2,000 MW) is returned to service as planned, resources are forecast to be adequate for the remainder of the summer.

If the nuclear units do not return to service as planned, available Ontario resources are forecast to be below planning requirements throughout the summer. In this case, a small number of planned generator outages are at risk of being deferred or canceled, and imports will likely be required to meet peak demands. A combination of high demand levels under extreme weather conditions and lower than forecast levels of available generation could lead to significant reliance on imports. Sufficient imports are expected to be available throughout the summer, although requirements on occasion could approach the coincident import capability of approximately 4,000 MW.

Energy supplies within Ontario are expected to be adequate overall, but shorter-term energy deficiencies could arise as a result of higher-than-forecast forced outage situations, extreme demands, and other influencing factors.

Fuel supplies are judged to be adequate during the summer peak demand, and no fuel delivery problems are anticipated.

The Ontario transmission system is expected to be adequate to supply forecast summer demand.

The Michigan–Ontario Phase Angle Regulator (PAR) project has been further delayed and its completion is not expected until after the summer. This delay will reduce the transfer capability of the Michigan–Ontario interface and the ability to control parallel flows. As a result, the Michigan-Ontario interface and the Queenston Flow West interface in Ontario will continue to be susceptible to TLR curtailments.

Transfers from Michigan to Ontario are expected to be reduced on occasion by about 150 MW until about the end of July due to the forced outage of circuit B3N in Ontario as the result of a tower failure. Transfers from Ontario to Michigan are not expected to be affected.

Interregional transmission transfer capability studies have been conducted to determine levels of external assistance that can be imported during the forecast 2003 summer peak demand. The study results are reflected in the FCITCs in Figure 2.

There are no unusual operating conditions, environmental, or regulatory restrictions that are expected to affect the capacity availability anticipated for this summer. All known planned generator outages have been included in the IMO's adequacy assessment.

Hydro-Québec

Hydro-Québec's internal peak demand for summer 2003 is expected to be 21,739 MW in May 2003. The actual peak demand for summer 2002 was 22,522 MW. This is also the all-time summer peak demand. The winter peaking nature of the Hydro-Québec system is demonstrated by comparing these demands with the all-time winter peak demand of 34,989 MW, which occurred on January 14, 2003.

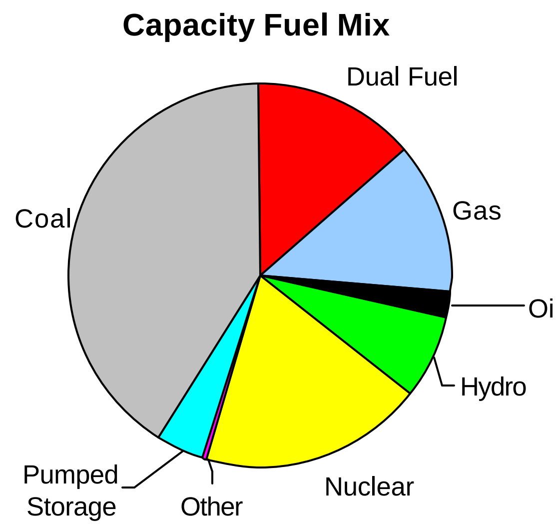
Net capacity resources are expected to be more than sufficient to meet expected internal demand, contractual obligations and reserve requirements during this summer 2003. The available capacity margin is expected to be over 6,000 MW throughout the summer, reaching a peak around 8,100 MW during July. Based on the level of current water reserves in Hydro-Québec's reservoirs and the availability of other resources, Hydro-Québec's generation availability meets the energy reliability criterion.

In May 2003, the 432 MW unit 1 will be added to the system at the Sainte-Marguerite 3 hydro generating station. However, during the summer period, this new unit will be operated at a reduced output of 300 MW. Another 432 MW generator was announced for Sainte Marguerite in the NERC *2001/2002 Winter Assessment*, but its in-service date has since been delayed.

Hydro-Québec's energy requirements are largely produced by hydro generating stations located on different river systems scattered throughout the province of Québec. The major plants are backed by multi-annual reservoirs (water reserves lasting more than a year), and Hydro-Québec can rely on those reservoirs, together with a certain amount of non-hydraulic resources, including fossil generation, to cope with inflow variations. The energy reliability criterion states that Hydro-Québec's system should withstand a sequence of low annual inflows comparable to the worst two consecutive low inflow years registered since 1943.

SERC

Projected Internal Demand	157,371 MW
Interruptible Demand & DSM	5,560 MW
Projected Net Internal Demand	151,811 MW
Last Summer's Peak Demand	157,333 MW
Change	0.02%
All-Time Summer Peak Demand	157,333 MW
Net Operable Capacity	167,579 MW
Projected Purchases	13,232 MW
Projected Sales	3,203 MW
Adj. to Purchases & Sales	(210)MW
Net Capacity Resources	177,398 MW
Capacity Margin	14.4%
Reserve margin	16.9%



Demand

SERC projects the total internal demand for the 2003 summer season to be 157,371 MW. This projection is based on average historical summer weather. The forecast 2003 summer peak is 1,531 MW (0.9%) lower than the forecast 2002 summer peak and is 38 MW (0.02%) higher than the actual 2002 summer peak. Interruptible demand and demand-side management capabilities decreased to 5,560 MW from the 6,095 MW reported last summer. Temperatures higher or lower than normal and the utilization of interruptible demand and demand-side management can significantly impact the actual peak demand for the Region.

Resources

Capacity resources in SERC are expected to be adequate to supply the projected firm summer demand: the projected 2003 summer capacity margin is 14.4%. This is slightly higher than last year's projected capacity margin of 13.1%. Planned transactions across the SERC electrical borders include 1,214 MW of purchases coming into the Region and 2,667 MW of sales leaving the Region. These transactions plus a net of 11,482 MW of purchases from non-SERC members that are located within the Region have been included in the capacity margin.

Merchant Generation

There has been significant merchant generation development in SERC for the past few years, especially in the Southern and Entergy subregions. Much of this merchant generation has not been contracted to serve load within SERC and its deliverability is not assured. For these reasons, only merchant generation contracted to serve SERC load is included in reported capacity margins.

To understand the extent of generation development in the Region, it is instructive to examine how much generation is connected to the transmission system. As of December 31, 2002, total generation connected to the transmission system in SERC was 200,744 MW, including uncommitted merchant generation. An additional 22,216 MW of generation is expected to connect to the transmission system by July 1, 2003, bringing the total to 222,960 MW. This connected generation exceeds forecast peak demand by 69,585 MW or 45%. As much as 46,000 MW of this connected generation may be excess to what is needed for reliability in the Region.

Transmission

SERC has extensive transmission interconnections between its subregions. SERC also has extensive interconnections to the ECAR, FRCC, MAAC, MAIN, MAPP and SPP. For interconnections of 161 kV and above, the voltage and number of interconnections at that voltage are shown in Figure SERC 1. These interconnections permit the exchange of large amounts of firm and non-firm power and allow systems to assist one another in an emergency.

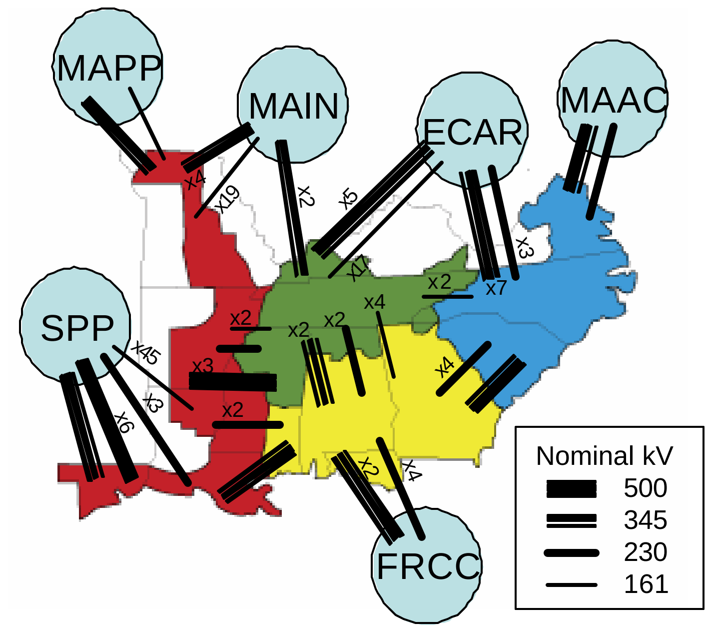


Figure SERC 1— SERC Regional and Subregional Interconnections

Approximately 304 miles of new 230 kV and 500 kV transmission lines were built and numerous transmission upgrades were completed throughout the Region in the past last year. In addition, a new ten-mile double circuit 230 kV interconnection between Duke Power and Santee Cooper is scheduled to be in service by this summer. SERC members invested more than $1 billion in new transmission lines and system upgrades in 2002 and plan to invest approximately $1.1 billion in 2003.

Coordinated interregional transmission studies were conducted among all the SERC subregions and with its neighboring Regions. They indicate that the bulk transmission systems within SERC and between adjoining Regions can be expected to provide adequate and reliable service over a range of system operating conditions. No significant problems or limits to transfers were identified that would raise reliability concerns.

Operations

The drought conditions that existed in many parts of SERC last summer have been relieved by significant rains during the fall and winter. Drought is not expected to raise reliability concerns for the 2003 summer. Environmental restrictions are not anticipated to significantly impact operations. Fuel supplies are expected to be adequate and no delivery problems are anticipated. No major generating units have planned outages during the summer.

Large and unpredictable power flows can be expected across portions of SERC. These flows are generally associated with differences in weather conditions within SERC or between SERC and other Regions, and large amounts of available surplus generation, or unusually high forced outages within SERC also play an important role in determining how these flows occur. Critical facilities that were identified through coordinated interregional studies will be monitored to maintain reliability should these flows occur. Operating procedures are in place where needed to maintain reliability for outages of key transmission facilities.

Subregions

Entergy

The projected total internal demand for the 2003 summer season is 26,002 MW based on normal weather conditions. This is 737 MW (2.8%) lower than the forecast 2002 summer peak and is 2 MW (0.01%) higher than the actual 2002 summer peak. The projected capacity margin in the subregion is 17.2%. Capacity in the subregion should be adequate to supply forecast demand.

No reliability problems are anticipated on the Entergy transmission system. However, large south-to-north flows across the eastern part of the subregion and large west-to-east flows across the southern part of the subregion are a result of merchant generation in the subregion. This flow pattern reduces the loading on the Webre – Richard 500 kV line that had previously been a limiting element. However, these flows have increased the loading on the McKnight – Franklin 500 kV line and the Ray Braswell 500 kV line. An operating procedure is available to relieve loading on the McKnight–Franklin 500 kV line if needed. The New Madrid 500/345 kV transformer failed in January 2002, which impacts the capability of the New Madrid–Dell 500 kV flowgate. A new transformer is expected to be in service prior to the summer. Numerous transmission projects are under way for the purpose of connecting new merchant generation.

Southern

The projected total internal demand for the 2003 summer season is 45,378 MW and is based on normal weather conditions. This is 611 MW (1.3%) lower than the forecast 2002 summer peak and is 165 MW (0.4%) higher than the actual 2002 summer peak. The projected capacity margin in the subregion is 12.7%. In addition to the resources included in the capacity margin calculation, there are approximately another 1,250 MW in demand side options available during peak periods. There are also large amounts of merchant generation in the subregion. Capacity in the subregion should be adequate to supply forecast demand.

A new 500/230 kV transformer at the Clay substation is scheduled for installation in 2003 and will increase transfer capabilities across the Southern–TVA interface. However, heavy and unpredictable loop flows are expected on the Southern system and the TVA–Southern interface based on past experience. Flows seem to be driven by the large amounts of uncommitted merchant generation within the subregion and weather conditions outside the subregion. Transfers into and out of FRCC can also result in volatile flow patterns. Transmission constraints may occur on the 230 kV systems around Atlanta depending upon the specific flow patterns that are being experienced. Operational procedures will be used to manage the situation should it occur and these constraints are not expected to threaten reliability. Coordinated transmission studies with the other SERC subregions and with FRCC have not identified any constraints restricting full operation of committed generation to serve area demand.

TVA

The projected total internal demand for the 2003 summer season is 29,909 MW based on normal weather conditions. This is 193 MW (0.6%) higher than the forecast 2002 summer peak and is 753 MW (2.6%) higher than the actual 2002 summer peak. The projected capacity margin in the subregion is 12.8%. Capacity in the subregion should be adequate to supply forecast demand.

The TVA transmission system experienced large and volatile flows in recent years that may occur again this summer. These flows seem to be driven by the large amounts of uncommitted generation to the south and weather conditions to the north of the subregion. The Bull Run–Volunteer–Phipps Bend 500 kV transmission corridor in eastern Tennessee could experience congestion as a result of these flows. Coordinated studies with ECAR, MAIN, and the other SERC subregions indicate that there will be adequate transmission transfer capability on all interfaces this summer to support firm transactions. No significant internal constraints were identified that would present a reliability concern.

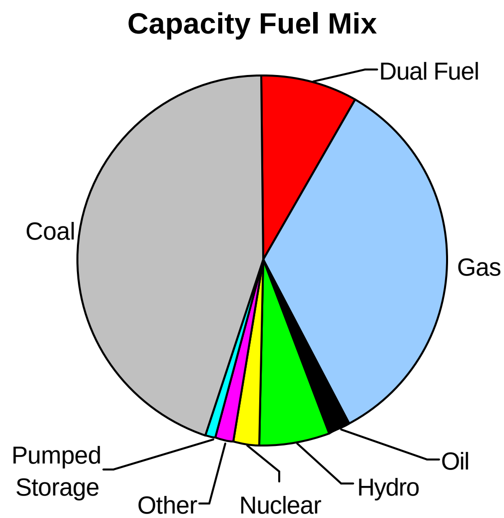
VACAR

The projected total internal demand for the 2003 summer season is 56,735 MW based on normal weather conditions. This is 1,179 MW (2.0%) lower than the forecast 2002 summer peak and 1,488 MW (2.6%) lower than the actual 2002 summer peak. The projected capacity margin in the subregion is 15.6%. Capacity in the subregion should be adequate to supply forecast demand.

Coordinated studies with ECAR, MAAC, and the other SERC subregions indicate that there will be adequate transmission transfer capability on all interfaces this summer to support firm transactions and significant amounts of economy transactions. No internal constraints were identified that would present a reliability concern.

SPP

Projected Internal Demand	40,126 MW
Interruptible Demand & DSM	1,420 MW
Projected Net Internal Demand	38,706 MW
Last Summer's Peak Demand	39,571 MW
Change	1.4%
All-Time Summer Peak Demand	40,101 MW
Net Operable Capacity	44,616 MW
Projected Purchases	7,740 MW
Projected Sales	4,766 MW
Adj. to Purchases & Sales	—
Net Capacity Resources	47,590 MW
Capacity Margin	18.7%
Reserve Margin	23.0%



Demand

SPP's noncoincident total internal demand forecast for the summer peak month of August is 40,126 MW, which is 2.4% higher than the adjusted 2002 actual summer peak noncoincident monthly demand of 39,571 MW. Actual demands for summer 2002 did not reach forecasted levels as a result of the relatively mild weather patterns across the Region. Actual peak demand has grown at 1.25% per year from 1998 to 2002.

Resources

SPP will add 535 MW of generating capacity to the Region prior to this summer. However, these resources represent only a small portion of total capacity from IPPs that could be available. Only 198 MW of this new reported generation is committed to firm, off-system sales or native load. Significant amounts of uncommitted resources exist within SPP. Merchant capacity that has been placed under firm contract is reflected in SPP's capacity resource calculation. An excess of 8,000 MW of merchant capacity has been interconnected within SPP, but is not included in those calculations for this summer.

SPP expects to be a net exporter of 183 MW during the 2003 summer peak period. The forecasted regional capacity margin for July is 18.8%, which exceeds the SPP criteria minimum requirement of 12%.

Fuel supply for SPP generating units is expected to be adequate for the summer months. SPP hydroelectric reservoirs have improved to above normal for this time of year, and normal hydro capacity is expected for this summer. The hydro energy output is not expected to have regional impact since only a small percentage of SPP capacity is hydro-based. There are no known environmental and/or regulatory restrictions expected to impede reliability during the summer months.

Transmission

SPP does not anticipate operational issues for the upcoming summer months. Last summer, SPP experienced a higher-than-normal level of TLR activity due to regional coordination issues surrounding the LaCygne–Stilwell 345 kV flowgate in the Kansas City area. The LaCygne–Stilwell 345 kV line is a critical outlet for large base-load generating units owned by Westar Energy and Kansas City Power & Light Company (KCP&L). It is also heavily impacted by merchant activity in SPP, as well as in SERC and MAPP. The transmission line has been a constraint in the region in recent history. This circuit's capacity will be upgraded from 1,251 MVA to 1,972 MVA. KCP&L is responsible for constructing the upgrade; the target completion date is July 1, 2003.

The 30-mile transmission line, located south-southwest of Kansas City, will be rebuilt using new technology that allows the use of existing structures and for the work to be done while the line is "hot" (i.e., energized) resulting in minimal disruption to the transmission market. The funding for this project results from the agreement approved by the FERC among the SPP transmission owners.

Based on the most recent analysis of the SPP, MAIN, MAPP, and SERC interfaces, completed by the MAIN Transmission Assessment Study Group, all SPP Regional import interfaces are found to be limited by the Fort Smith 500/161 kV transformer (OKGE) for the outage of Fort Smith 345/161 kV transformer (OKGE). While this limitation was consistent for all the interfaces studied, all transfer levels are judged to be adequate.

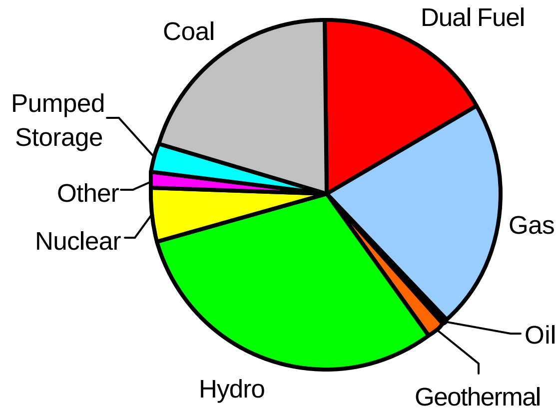
Operations

No operational issues are expected by the Region for the summer.

WECC

Projected Internal Demand	136,587 MW
Interruptible Demand & DSM	1,821 MW
Projected Net Internal Demand	134,766 MW
Last Summer's Peak Demand	136,108 MW
Change	0.4%
All-Time Summer Peak Demand	136,108 MW
Net Operable Capacity	177,239 MW
Projected Purchases	286 MW
Projected Sales	103 MW
Adj. to Purchases & Sales	—
Net Capacity Resources	177,422 MW
Capacity Margin	24.0%
Reserve Margin	31.7%

Capacity Fuel Mix



Demand

The aggregate 2003 WECC summer total internal demand is forecast to be 136,587 MW (U.S. systems 119,320 MW, Canadian systems 15,513 MW, and the Mexican system 1,754 MW). The forecast is based on average weather conditions, and is 0.4% above last summer's actual peak demand, which was established under generally normal to above normal temperatures in the Region.

Resources

WECC resources are expected to increase by about 10,900 MW from September 2002 through August 2003, while peak demands are expected to be up by about 500 MW. Consequently, expected capacity margins have increased compared to last summer. For the peak summer month of August, WECC's capacity margin is expected to be 24%. However, WECC is a large geographical region. If multiple areas peak simultaneously, portions of the Region may need to take action to reduce electricity consumption and ensure that adequate operating reserves are maintained.

Transmission

WECC conducts extensive operating studies that model the transmission system under a number of load and resource scenarios and develops operating procedures to maintain safe and reliable operations. The transmission system is considered adequate for all projected firm transactions and most economy energy transfers. Fuel supplies are expected to be adequate in all areas of the Region under normal summer weather conditions. Additional information is available in the following area assessments.

A recent 500/230 kV transformer failure will limit north-to-south transfers within California until a replacement transformer bank is installed in late summer. Operating procedures may have to be implemented during high demand periods to limit flows on critical facilities.

Operations

No operational issues are expected by the Region for the summer.

Subregions

California–Mexico Power Area

This is a summer-peaking area. The 2003 summer peak demand forecast of 53,334 MW is 2.1% above last summer's actual peak demand of 52,230 MW. Area resources are expected to increase by about 3,500 MW since last summer. The forecast peak demand includes 1,251 MW of interruptible demand capability and 69 MW of load management. The projected capacity margin for the peak month is 20.0%.

California ISO Control Area (CAISO)

Demand Forecast — The CAISO summer peak demand forecast for normal weather conditions is 42,894 MW, which is 1.1% greater than the 2002 summer peak demand of 42,441 MW but 1.5% less than the July 1999 all-time peak demand of 43,554 MW

A portion of the peak demand forecast represents customer demand that is subject to voluntary interruption. In previous years, various programs provided up to 2,800 MW of interruptible demand. However, the same programs provided only 1,600 MW in 2001, and 1,409 MW in 2002. For this summer, customer commitment for voluntary load reduction is estimated to be 1,321 MW. There are restrictions on utilizing the voluntary demand reductions, including limitations on the number of activations per day (generally one) and the number of activations per year. Customers participating in the interruptible demand programs are limited to commercial, industrial, agricultural, and air conditioning loads. CAISO also has approximately 1,250 MW of non-spinning reserves that can be converted to energy, giving a total of 2,571 MW of emergency mitigation measures that can be implemented prior to curtailing firm peak demand.

Resource Assessment — Barring major generation or transmission outages, CAISO anticipates sufficient capacity margins throughout the summer season to serve forecast peak demand and meet minimum operating reserve requirements. A total of 2,764 MW of new generation was added within the area in 2002 and 3,605 MW of additional generation is expected to be in service prior to June 2003. While approximately 1,409 MW of generation capacity reductions were identified in 2002, the resulting net increase in in-area resources has increased the area's ability to meet peak demand requirements.

Environmental Issues — All power plants in California are required to operate in accordance with strict air quality environmental regulations. Some plant owners have upgraded emission control equipment to remain in compliance with increasing emission limitations while other owners have chosen to discontinue operating some plants. However, the effects of owners' responses to environmental regulations have been accounted for in the area's resource data and it is not expected that environmental issues will have additional adverse impacts on resource adequacy within the CAISO control area.

Transmission System Assessment — A recent 500/230 kV transformer failure will limit north-to-south transfers within California until a replacement transformer bank is installed in late summer. Operating procedures may have to be implemented during high demand periods to limit flows on critical facilities.

Southern California Edison area imports may increase due to the shutdown of 770 MW of generation in the area. Despite several transmission system upgrades, the area's South of Lugo transmission path may be constrained, even during normal system conditions. However, the path constraint is not expected to adversely affect reliability.

Comision Federal de Electricidad Control Area (CFE)

Adequate resources are expected in the CFE control area for summer 2003. The area has adequate internal transmission and transmission interconnection capability and fuel availability is expected to be adequate. The area reports having no concerns with maintaining adequate reactive reserves and expects to have excess resources available for capacity and energy sales to other control areas.

Los Angeles Department of Water and Power Control Area (LDWP)
The LDWP control area anticipates adequate resources for the 2003 summer period. The area expects adequate fuel availability and has adequate internal transmission and transmission interconnection capability. The area reports having no concerns with maintaining adequate reactive reserves and expects to have excess resources available for capacity and energy sales to other control areas.

Sacramento Municipal Utility District Control Area (SMUD)
The SMUD control area is highly dependent on imports to meet its peak demand and energy load requirements. Capacity resources have been acquired to meet the forecast peak demand and reactive reserve margins are expected to be adequate. There are no transmission constraints expected during the summer period under typical operating conditions. Under extreme conditions, transmission constraints will be relieved by generation redispatch or other measures.

Arizona–New Mexico–Southern Nevada Power Area
This is a summer-peaking area. The 2003 summer peak demand forecast of 25,406 MW is 4.9% above last summer's actual peak demand of 24,222 MW. Area resources are expected to increase by about 5,000 MW over last summer. The forecast for the area includes 255 MW of load management and interruptible demand capability. The projected capacity margin for the peak month is 17.1%.

Based on inter and intra-area studies, the transmission system is considered adequate for projected firm transfers and a significant amount of economy electricity transfers. If necessary, phase-shifting transformers in the southern Utah/Colorado/Nevada transmission system will be used to help control unscheduled flows. Reactive reserve margins have been studied and are expected to be adequate throughout the area.

Fuel supplies are expected to be adequate to meet summer peak demand conditions. The area is experiencing severe drought conditions and reduced water flows are anticipated on many Colorado River and other tributaries. However, due to reservoir storage capability, it is expected that the below-normal precipitation will not adversely affect hydroelectric generation.

Rocky Mountain Power Area
The Rocky Mountain Power Area's peak demand may occur in either summer or winter. The 2003 summer peak demand forecast of 10,089 MW is 2.0% above last summer's actual peak demand of 9,891 MW. Resources are expected to increase by about 800 MW over last summer. The forecast peak demand includes five MW of interruptible demand capability. The projected capacity margin for the peak month is 12.5%.

Water inflows into the hydro system are expected to be slightly below average this year. However, since much of the area's hydro system is designed for multiple dry years, the current below-average storage conditions are not expected to affect adequacy of supply. The Glen Canyon power plant is operating under environmental impact restrictions that limit water releases. The release limitations reduce peaking capability by about 450 MW, but the plant will be able to respond to short-term emergency conditions.

The transmission system is expected to be adequate for all firm transfers and most economy energy transfers. However, the transmission path between southeastern Wyoming and Colorado often becomes heavily loaded, as do the transmission interconnections to Utah and New Mexico. Consequently, the WECC Unscheduled Flow Mitigation Procedure may be invoked on occasion this summer to provide line loading relief for these paths.

Reactive reserve margins are expected to be adequate for all peak load conditions.

Northwest Power Pool (NWPP) Area

NWPP is a winter peaking area. Due partially to last summer's above-average temperatures in portions of the area, the 2003 summer peak demand forecast of 48,704 MW for the combined Northwest United States and Canadian areas is 2.1% below last summer's actual peak demand of 49,765 MW. Area resources are expected to increase by about 1,600 MW over last summer. The summer peak demand forecast includes 250 MW of load management and interruptible demand. The projected capacity margin for the peak month is 30.7%.

NWPP is comprised of all or major portions of the states of Idaho; Montana; Nevada; Oregon; Utah; Washington; and Wyoming; a small portion of Northern California; and the Canadian provinces of Alberta and British Columbia. Barring degradation in hydro conditions from current forecasts, the extended loss of a major thermal unit, or load significantly in excess of the forecast peak demand or energy requirement, the region is expected to be able to meet firm loads and maintain required reserves for the 2003 summer under normal temperature conditions.

The 2003 April "Early Bird" forecast for the January through July volume runoff (Columbia River flows) at The Dalles, Oregon, is 77% of average. Under normal weather conditions, NWPP does not anticipate depending on imports from external areas during summer peak demand periods. However, if the lower-than-normal precipitation continues, the area may import electric power to reduce reservoir drafts.

The water flow associated with hydro-powered resources must balance several competing purposes, including but not limited to current electric power generation, future electric power generation, flood control, biological opinion requirements resulting from the Endangered Species Act, as well as special river operations for recreation, irrigation, navigation, and the refilling of the reservoirs each year. Any time precipitation levels are below normal, balancing these interests becomes difficult.

Constrained transmission paths within the NWPP area have been identified, operating studies modeling these constraints have been performed and operating procedures have been developed to ensure safe and reliable operations. The transfer capabilities of the West of Hatwai, the Northwest U.S.–British Columbia, and the North-of-John-Day transmission paths will be reduced at times due to transmission line construction projects. It is expected that these transfer reductions will not adversely affect safe and reliable operation of the transmission system.

Appendix 1: Generating Unit Additions Scheduled for Initial Service, Retirement or Rerating March through September 2003

Region	Unit	MW Change	Type	Fuel	Action	Scheduled Operating Date
ECAR	Waterford Energy 1-4	850	Combined Cycle	Natural Gas	New	June
	Noblesville 1-2	(90)	Steam	Coal	Retire	May
	Noblesville	318	Combined Cycle	Natural Gas	New	June
	Dresden 1-3	594	Comb. Turbine	Natural Gas	New	June
	Hanging Rock 1-6	1,240	Combined Cycle	Natural Gas	New	June
	Fayette Energy 1-3	620	Combined Cycle	Natural Gas	New	June
	Rolling Hills 1-5	875	Comb. Turbine	Natural Gas	New	June
	Covert	1,170	Combined Cycle	Natural Gas	New	June
	Sugar Creek phase II	228	Combined Cycle	Natural Gas	New	June
	Springdale	556	Combined Cycle	Natural Gas	New	June
ERCOT	AES Wolf Hollow 1	225	Comb. Turbine	Natural Gas	New	March
	AES Wolf Hollow 2	225	Comb. Turbine	Natural Gas	New	March
	AES Wolf Hollow 3	293	Combined Cycle Steam Turbine	Natural Gas	New	March
	Brazos Valley 1	199	Comb. Turbine	Natural Gas	New	April
	Brazos Valley 2	199	Comb. Turbine	Natural Gas	New	April
	Brazos Valley 3	276	Combined Cycle Steam Turbine	Natural Gas	New	April
	Deer Park Energy Center 1	206	Comb. Turbine	Natural Gas	New	August
	FPL Forney 1A	157	Comb. Turbine	Natural Gas	New	April
	FPL Forney 1B	157	Comb. Turbine	Natural Gas	New	April
	FPL Forney 1C	157	Comb. Turbine	Natural Gas	New	April
	FPL Forney 1D	157	Comb. Turbine	Natural Gas	New	April
	FPL Forney 2A	157	Comb. Turbine	Natural Gas	New	April
	FPL Forney 2B	157	Comb. Turbine	Natural Gas	New	April
	FPL Forney 2C	411	Combined Cycle Steam Turbine	Natural Gas	New	April
	FPL Forney 2D	411	Combined Cycle Steam Turbine	Natural Gas	New	April
	Rayburn 7	52	Comb. Turbine	Natural Gas	New	June
	Rayburn 8	52	Comb. Turbine	Natural Gas	New	June
	Rayburn 9	52	Comb. Turbine	Natural Gas	New	June
	Rayburn 10	42	Combined Cycle Steam Turbine	Natural Gas	New	June
	Noelke Wind Ranch 1	80	Wind Turbine	Wind	New	September
FRCC	Gannon 1	(94)	Steam	Coal	Deactivated Reserve	April
	Gannon 2	(100)	Steam	Coal	Deactivated Reserve	April
	Bayside 1	690	Combined Cycle	Natural Gas	New	May
	Gannon 5	(222)	Steam	Coal	Repowering Project	May
	Ft. Myers 13	149	Comb. Turbine	Natural Gas	New	June
	Ft. Myers 14	149	Comb. Turbine	Natural Gas	New	June

Appendix 1: Generating Unit Additions Scheduled for Initial Service, Retirement or Rerating March through September 2003

Region	Unit	MW Change	Type	Fuel	Action	Scheduled Operating Date
FRCC	Sanford 4	957	Comb. Turbine	Natural Gas	Repowering Project	June
	Gannon 3	(150)	Steam	Coal	Repowering Project	September
	Gannon 4	(164)	Steam	Coal	Repowering Project	September
MAAC	D25 Hay Road	39	Combined Cycle	Natural Gas	Uprate	June
	B19 Melrose	20	Combined Cycle	Natural Gas	New	June
	D01 Sight and Sound	1.6	Int. Combustion	Landfill Gas	New	June
	B46 Conowingo	36	Hydro	Water	Uprate	June
	F07 Dickerson H	16	Comb. Turbine	Natural Gas	Uprate	June
	F08 Chalk Point	6	Steam	Coal	Uprate	June
	G08 Kearny	7	Steam	Oil	Uprate	June
	G18 Linden	12	Comb. Turbine	Natural Gas	Uprate	June
	G22 Merck	38	Comb. Turbine	Natural Gas	New	June
	G04 Brunner Island	14	Steam	Coal	Uprate	June
	A54 TMI	45	Nuclear	Uranium	Uprate	June
	C15 Friedensburg	5	Int. Combustion	Landfill Gas	New	June
	D11 DEMEC	100	Comb. Turbine	Natural Gas	New	June
	G19 Linden	12	Combined Cycle	Natural Gas	Uprate	June
	G20 Essex	6	Comb. Turbine	Natural Gas	Uprate	June
	G44 Dupont Seaford	10	Steam/	Waste Heat	Uprate	June
	H27 Marion	1.9	Internal Combustion	Landfill Gas	New	June
	A29 Colora Tap	465	Combined Cycle	Natural Gas	New	June
	G05 Brunner Island #1	14	Steam	Coal	Uprate	June
	G46 Peach Bottom	70	Nuclear	Uranium	Uprate	June
	H13 Dolfield 33 kV	9	Int. Combustion	Kerosene	New	June
	B03 Hosensack-Steel City (Beth)	175	Combined Cycle Steam Turbine	Natural Gas	New	June
	H20 Oak Grove	3.5	Comb. Turbine	Natural Gas	New	June
	A55 Lakewood	500	Combined Cycle	Natural Gas	New	June
MAIN	Hancock Wind Farm	100	Wind Turbine	Wind	New	In-Service
	Keokuk	10	Hydro	Water	Uprate	In-Service
	Osage	14	Hydro	Water	Uprate	In-Service
	Meramec	14	Steam	Coal	Uprate	In-Service
	Marion 5,6	142	Comb. Turbine	Natural Gas	New	July
	Labadie 1,2,3	90	Steam	Coal	Uprate	In-Service
	Rush Island 1	28	Steam	Coal	Uprate	In-Service
	Venice 3,4,5,6	(368)	Int. Combustion	Diesel	Retire	In-Service
	Meredosia 1,2	(126)	Steam	Coal	Deactivated Reserve	In-Service
	Goose Creek	477	Comb. Turbine	Natural Gas	New	In-Service
	Escanaba 3	18	Comb. Turbine	Natural Gas	New	In-Service
	Big Pond 1	18	Comb. Turbine	Natural Gas	New	In-Service

Appendix 1: Generating Unit Additions Scheduled for Initial Service, Retirement or Rerating March through September 2003

Region	Unit	MW Change	Type	Fuel	Action	Scheduled Operating Date
MAIN	Pulliam 31	75	Comb. Turbine	Natural Gas	New	July
	Appleton Papers	50	Comb. Turbine	Natural Gas	New	In-Service
	Will County 1,2	(299)	Steam	Coal	Retire	In-Service
	Zion Energy Center	165	Comb. Turbine	Natural Gas	New	In-Service
	Collins 2 Units	(1,076)	Comb. Turbine	Natural Gas	Deactivated Reserve	In-Service
	Port Washington 4	(80)	Steam	Coal	Retire	In-Service
	Port Washington 6	(20)	Int. Combustion	Diesel	Retire	In-Service
	Kaukanna	(6)	Int. Combustion	Oil	Retire	In-Service
MAPP–Canada	None	—	—	—	—	—
MAPP–US	MPC – Oxbow #1	2	Int. Combustion	Distillate Fuel Oil	New	May
	MPC – Arthur #1	2	Int. Combustion	Distillate Fuel Oil	New	May
	MPC – Oxbow #2	2	Int. Combustion	Distillate Fuel Oil	New	May
	MPC – Arthur #2	2	Int. Combustion	Distillate Fuel Oil	New	May
	MPC – Reed #3	2	Int. Combustion	Distillate Fuel Oil	New	May
	MPC – Reed #4	2	Int. Combustion	Distillate Fuel Oil	New	May
	MPC – Reed #5	2	Int. Combustion	Distillate Fuel Oil	New	May
	MPC – Reed #6	2	Int. Combustion	Distillate Fuel Oil	New	May
	OTP – Perham Incinerator #1	2.5	Int. Combustion	Municipal Solid Waste	New	May
	OTP – Solway #1	43	Comb. Turbine	Natural Gas	New	May
	OTP – Solway #D1	1.25	Int. Combustion	Distillate Fuel Oil	New	May
	PELLA #3	2	Int. Combustion	Distillate Fuel Oil	New	May
	PELLA #4	2	Int. Combustion	Distillate Fuel Oil	New	May
	PELLA #5	2	Int. Combustion	Distillate Fuel Oil	New	May
	PELLA #6	2	Int. Combustion	Distillate Fuel Oil	New	May
	PELLA #7	2	Int. Combustion	Distillate Fuel Oil	New	May
	PELLA #8	2	Int. Combustion	Distillate Fuel Oil	New	May
	PELLA #9	2	Int. Combustion	Distillate Fuel Oil	New	May

Appendix 1: Generating Unit Additions Scheduled for Initial Service, Retirement or Rerating March through September 2003

Region	Unit	MW Change	Type	Fuel	Action	Scheduled Operating Date
MAPP–US	PELLA #10	2	Int. Combustion	Distillate Fuel Oil	New	May
	PELLA #11	2	Int. Combustion	Distillate Fuel Oil	New	May
	PELLA #12	2	Int. Combustion	Distillate Fuel Oil	New	May
	PELLA #13	2	Int. Combustion	Distillate Fuel Oil	New	May
	PELLA #14	2	Int. Combustion	Distillate Fuel Oil	New	May
	PELLA #15	2	Int. Combustion	Distillate Fuel Oil	New	May
	PELLA #16	2	Int. Combustion	Distillate Fuel Oil	New	May
	SMMPA – Blooming Prairie #5	2	Int. Combustion	Distillate Fuel Oil	New	June
	LES – Salt Valley #2	37	Comb. Turbine	Natural Gas	New	June
	LES – Salt Valley #3	37	Comb. Turbine	Natural Gas	New	June
	LES – Salt Valley BSU	2	Int. Combustion	Distillate Fuel Oil	New	June
	MEC – Greater Des Moines Energy Center GT1	155	Comb. Turbine	Natural Gas	New	June
	MEC – Greater Des Moines Energy Center GT2	155	Comb. Turbine	Natural Gas	New	June
	MDU – Glendive #2	39	Comb. Turbine	Natural Gas	New	June
	SMMPA – North Branch #4	4	Int. Combustion	Distillate Fuel Oil	New	June
	OPPD – Cass County #1	160	Comb. Turbine	Natural Gas	New	June
	OPPD – Cass County #2	160	Comb. Turbine	Natural Gas	New	June
	SMMPA – Princeton #7	5	Int. Combustion	Distillate Fuel Oil	New	June
	SMMPA – Redwood Falls #8	6	Int. Combustion	Distillate Fuel Oil	New	June
	SMMPA – Saint Peter #1	12	Int. Combustion	Distillate Fuel Oil	New	June
	LES – Salt Valley #4	37	Comb. Turbine	Natural Gas	New	July
	DPC – Lake Mills #1	6	Int. Combustion	Landfill Gas	New	September
	DPC – Seven Mile Creek #1	3	Int. Combustion	Landfill Gas	New	September
NPCC – Hydro-Québec	Ste-Marguerite 3 # 1	432	Hydro	Water	New	April

Appendix 1: Generating Unit Additions Scheduled for Initial Service, Retirement or Rerating March through September 2003

Region	Unit	MW Change	Type	Fuel	Action	Scheduled Operating Date
NPCC – Hydro-Québec	Ste-Marguerite 3 # 2	432	Hydro	Water	New	May
NPCC – Ontario IMO	Transalta–SRCP	510	Combined Cycle	Natural Gas	New	March
NPCC – Maritimes	Tufts Cove #4	49	Comb. Turbine	Natural Gas	New	September
NPCC – ISO NE	AES Granite Ridge	678	Combined Cycle	Natural Gas	New	Summer
	Mystic Units 8 & 9	1,414	Combined Cycle	Natural Gas	New	Summer
	Fore River	700	Combined Cycle	Natural Gas	New	Summer
	Great Northern Hydro	126	Hydro	Water	New	Summer
NPCC – NYISO	Athens	1,080	Combined Cycle	Natural Gas	New	July
	Far Rockaway #6	51	Comb. Turbine	Natural Gas	New	June
	Greenport	51	Comb. Turbine	Natural Gas	New	August
	Stony Brook	47	Comb. Turbine	Natural Gas	New	August
SERC– Entergy	Union Power Partners Unit 2	550	Steam	Natural Gas	New [4]	March
SERC– Southern	Chattahoochee	490	Combined Cycle	Natural Gas	New	March
	Talbot Co. Energy 5	108.7	Comb. Turbine	Natural Gas	New	June
	Talbot Co. Energy 6	108.7	Comb. Turbine	Natural Gas	New	June
	Atkinson 5A	(32)	Comb. Turbine	Oil	Environ. Derate [5]	May
	Atkinson 5B	(32)	Comb. Turbine	Oil	Environ. Derate [2]	May
	Bowen 6	(32)	Comb. Turbine	Oil	Environ. Derate [2]	May
	Franklin 2	615	Combined Cycle	Natural Gas	New	June
	Harris 1	615	Combined Cycle	Natural Gas	New	June
	Harris 2	615	Combined Cycle	Natural Gas	New	June
	Hatch 1	13	Nuclear	Uranium	Uprate	June
	Hatch 2	13	Nuclear	Uranium	Uprate	June
	McDonough 3A	(32)	Comb. Turbine	Oil	Environ. Derate [2]	May
SERC– Southern	McDonough 3b	(32)	Comb. Turbine	Oil	Environ. Derate [2]	May
	Wansley 5A	(49)	Comb. Turbine	Oil	Environ. Derate [2]	May
SERC– TVA	Guntersville 3	1.3	Hydraulic Turb.	Water	Uprate	June
	Sequoyah 1	13	Nuclear	Uranium	Uprate	June

4 Delay - Original In-Service Date December 2002.
5 Due to environmental constraints in the Atlanta area certain units will not operate during the summer.but will be available October-April each year.

Appendix 1: Generating Unit Additions Scheduled for Initial Service, Retirement or Rerating March through September 2003

Region	Unit	MW Change	Type	Fuel	Action	Scheduled Operating Date
SERC–VACAR	Possum Point 6	462	Combined Cycle	Natural Gas	New	May
	Mill Creek Units 5-8	284	Comb. Turbine	Nat. Gas/Oil	New	June
	Louisa Generating Unit 1	195.5	Comb. Turbine	Natural Gas	New	May
	Louisa Generating Unit 2	100.7	Comb. Turbine	Natural Gas	New	May
	Louisa Generating Unit 3	100.7	Comb. Turbine	Natural Gas	New	May
	Louisa Generating Unit 4	100.7	Comb. Turbine	Natural Gas	New	May
	Louisa Generating Unit 5	100.7	Comb. Turbine	Natural Gas	New	May
	Fairfield PS No. 1	8	Pumped Storage	Water	Uprate	June
	Fairfield PS No. 2	8	Pumped Storage	Water	Uprate	June
	Horry LFG #3	1.063	Int. Combustion	Other Biomass Gases	New	March
SPP	Empire Energy Center 4		Comb. Turbine	Natural Gas	New	April
	Empire Energy Center 4		Comb. Turbine	Natural Gas	New	April
	West Gardner 1	77	Comb. Turbine	Natural Gas	New	June
	West Gardner 2	77	Comb. Turbine	Natural Gas	New	June
	West Gardner 3	77	Comb. Turbine	Natural Gas	New	June
	West Gardner 4	77	Comb. Turbine	Natural Gas	New	June
	Oswatomie	77	Comb. Turbine	Natural Gas	New	June
	Ponca City	42	Comb. Turbine	Natural Gas	New	May
	Oklahoma Wind Energy Center	8	Wind Turbine	Wind	New	July
WECC – AZ–NM–SNV	Apex CC	533	Combined Cycle	Natural Gas	New	April
	Blythe CC	520	Combined Cycle	Natural Gas	New	April
	Gila River CC 1	500	Combined Cycle	Natural Gas	New	April
	Gila River CC 2	500	Combined Cycle	Natural Gas	New	May
	Harquahala CC	1,000	Combined Cycle	Natural Gas	New	September
	West Phoenix CC 5	529	Combined Cycle	Natural Gas	New	June
	Taiban	204	Wind Turbine	Wind	New	July
	Gila River CC 3	500	Combined Cycle	Natural Gas	New	June
WECC – AZ–NM–SNV	Pyramid GT 1-4	160	Comb. Turbine	Natural Gas	New	June
	Mesquite CC	625	Combined Cycle	Natural Gas	New	June
	Gile River CC 4	500	Combined Cycle	Natural Gas	New	August
WECC – CA–MX	La Paloma CC 2	255	Combined Cycle	Natural Gas	New	March
	La Paloma CC 4	255	Combined Cycle	Natural Gas	New	March
	Los Esteros GT 1-4	196	Comb. Turbine	Natural Gas	New	March
	Tracy GT 1	83	Comb. Turbine	Natural Gas	New	March
	Tracy GT 2	83	Comb. Turbine	Natural Gas	New	April
	Wolfskill GT	49	Comb. Turbine	Natural Gas	New	April

Appendix 1: Generating Unit Additions Scheduled for Initial Service, Retirement or Rerating March through September 2003

Region	Unit	MW Change	Type	Fuel	Action	Scheduled Operating Date
WECC – CA–MX	La Rosita I	735	Combined Cycle	Natural Gas	New	April
	La Rosita II	315	Combined Cycle	Natural Gas	New	April
	Mid Valley	2	Int. Combustion	Landfill Gas	New	April
	Colton	1	Int. Combustion	Landfill Gas	New	April
	Elk Hills	549	Combined Cycle	Natural Gas	New	May
	High Desert	865	Combined Cycle	Natural Gas	New	May
	Riverview	49	Comb. Turbine	Natural Gas	New	June
	Milliken	2	Int. Combustion	Landfill Gas	New	June
	El Dorado 1-2	20	Hydroelectric	Water	New	June
	Castaic 1	10	Pumped Storage	Water	Uprate	June
	Sunrise CC	200	Combined Cycle	Natural Gas	New	July
	TDM CC	600	Combined Cycle	Natural Gas	New	July
	Woodland II	80	Combined Cycle	Natural Gas	New	July
	High Winds	150	Wind Turbines	Wind	New	August
	El Sobrante	3	Int. Combustion	Landfill Gas	New	September
WECC – NWPP	Bear Creek CC G3	30	Combined Cycle	Natural Gas	New	March
	Foster Creek 1	40	Comb. Turbine	Natural Gas	New	March
	Pingston 1-2	30	Hydroelectric	Water	New	March
	Calgary EC CC1A	150	Combined Cycle	Natural Gas	New	March
	Calgary EC CC1B	100	Combined Cycle	Natural Gas	New	April
	Foster Creek 2	40	Comb. Turbine	Natural Gas	New	April
	Syncrude G11-12	100	Combined Cycle	Natural Gas	New	April
	Miller Creek 1	25	Hydroelectric	Water	New	April
	Oldman 1-2	32	Hydroelectric	Water	New	April
	Seven Mile 4	198	Hydroelectric	Water	New	April
	U Bonnington	2	Hydroelectric	Water	Uprate	April
	Waneta 1	25	Hydroelectric	Water	Uprate	May
	McBride Lake	75	Wind Turbines	Wind	New	May
	Medicine Hat 13	42	Comb. Turbine	Natural Gas	New	June
	Coyote Springs II	260	Combined Cycle	Natural Gas	New	June
	Scotford CC	180	Combined Cycle	Natural Gas	New	June
	Thompson River	12	Steam Turbine	Wood Waste	New	July
	Chehalis CC	520	Combined Cycle	Natural Gas	New	September
WECC – RMPA	Front Range CC	472	Combined Cycle	Natural Gas	New	April
	WYGEN 1	75	Steam Turbine	Coal	New	March
	Blue Spruce CC	280	Combined Cycle	Natural Gas	New	April

Appendix 2: Transmission System Additions and Upgrades (230 kV and Above) March through September 2003

Region	Facility	Length Miles	N/E Capacity MVA	Voltage kV	Action	Expected Operating Date
ECAR	Cornu Hanging Rock	1.0	1,500 / 1,500	765	Loop into IPP	June
	Ronco / Hatfield – Fort Martin	—	No change	230	Loop into station	June
	Old Farm / Monocacy – Ringgold	1.0	No change	230	Loop into station	June
	Lime Kiln / Doubs – Monocacy – Ringgold	—	No change	230	Loop into station	June
ERCOT	Morgan Creek – Twin Buttes	65	1,515	345	New	June
	Twin Buttes – Red Creek	35	1,515	345	New	June
	Red Creek – Comanche	107	1,515	345	New	May
	Watermill – Cedar Hill	17.7	1,515	345	New	June
	Watermill – West Levee	17.7	1,631	345	New	June
	Mustang Creek – Tractebel	5	1,631	345	New	June
	Forney – Centerville	14.9	1,631	345	New	June
	Watermill – Tricorner	11.4	1,631	345	New	June
	Royce Autotransformer	—	600	345 / 138	New	May
	Liggett Autotransformer	—	600	345 / 138	New	May
	Rocky Creek Autotransformer	—	600	345 / 138	New	June
	Collin Autotransformer	—	600	345 / 138	New	June
	Centerville Autotransformer	—	600	345 / 183	New	May
FRCC	Hines – Barcola #2	3	1,146	230	New	May
	Barcola – Pebbledale	1	1,013	230	Rebuild	June
	Broward – Delmar	3	514	230	New	June
	Charlotte – Whidden #2	29	1,191	230	New	June
	Cortez – Johnson	11	596	230	New	June
	Duval – Kingsland – Yulee – Oneil	7	578	230	New	June
	Gannon – Juneau	14	1,100	230	New	June
	Recker – So. Eloise	17	749	230	New	August
MAAC	None	—	—	—	—	—
MAIN	Lisle Transformer 3	—	300	345 / 138	New	June
	Newton Transformer 1 & 2	—	450	345 / 138	Uprate	March
	Cahokia Transformer 9	—	700	345 / 138	Uprate	June
	Wildwood Transformer 1	—	560	345 / 138	New	June
	Forest Jct. Transformer 1&2	—	500	345 / 138	New	March
	Rush Is. – St. Francois – 2	17	1,793 / 1,793	345	New	June
	Adams – Hazleton	105	956 / 956	345	Uprate	March
MAPP – Canada	None	—	—	—	—	—

Appendix 2: Transmission System Additions and Upgrades (230 kV and Above) March through September 2003

Region	Facility	Length Miles	N/E Capacity MVA	Voltage kV	Action	Expected Operating Date
MAPP – US	Wilmarth – West Faribault	52.8		161	New	May
	Air Lake – Empire	18		115	New	May
	Red Rock – Rogers Lake	6		115	New	May
NPCC – Hydro-Québec	None	—	—	—	—	—
NPCC – IMO	Ontario – Michigan Ties — L4D Phase Shifter	—	845	220	New	July
NPCC – Maritimes	None	—	—	—	—	—
NPCC – ISO NE	Coolidge – West Rutland	27	1,200	345	Re-energize	June
	Coolidge breakers – 2	—		345	New	June
	West Rutland breakers – 2	—		345	New	June
	West Rutland transformers – 2	—	250 each	345 / 115	New	June
	Canal transformer – 1	—	550	345 / 115	New	June
	Canal breakers – 4	—		345	New	June
	Sherman Road breaker – 1	—		345	New	June
NPCC – NYISO	Bowline Point transformer	—	400	345 / 138	New	June
SERC – Entergy	Choctaw (Dow Meter Point) – Addis	4.35	685	230	New	September
	Choctaw (Dow Meter Point) – Dow	1.7	685	230	New	September
	Choctaw (Dow Meter Point) – Dow	1.7	685	230	New	September
	Cypress 230 / 138 kV Autotransformer (Intergen Cottonwood)	—	300	230 / 138	New	April
	Cypress 500 / 230 kV Autotransformer (Intergen Cottonwood)	—	750	500 / 230	New	April
	Getwell 230 / 115 kV Autotransformer (Duke Southhaven)	—	392	230 / 115	New	April
	Hartburg 500 / 230 kV Autotransformer (Intergen Cottonwood)	—	800	500 / 230	Upgrade	April
	Horn Lake – Freeport (Duke Southhaven)	3.81	392	230	New	April
	Horn Lake – Getwell (Duke Southhaven)	8.8	521	230	New	April
	Horn Lake 230 / 161 kV Autotransformer (Duke Southhaven)	—	400	230 / 161	New	April

Appendix 2: Transmission System Additions and Upgrades (230 kV and Above) March through September 2003

Region	Facility	Length Miles	N/E Capacity MVA	Voltage kV	Action	Expected Operating Date
SERC – Southern	Big Shanty – McConnell Road 230 kV Line	9	602	230	New	May
	East Moultrie – West Valdosta 230 kV Line	38	664	230	New	June
	East Moultrie – West Valdosta 230 kV	38	664	230	New	July
	Holcomb Bridge – Martins Landing 230 kV	3.4	664	230	New	September
	Holcomb Bridge – Martins Landing 230 kV	3	664	230	New	September
	McConnell Road 230 / 115 kV	—	400	230 / 115	New	September
	Spout Spring – Shoal Creek 230 kV	14	602	230	New	March
	Spout Spring – Shoal Creek 230 kV	14	602	230	New	March
	Yates – Line Creek 230 kV	17.4	602	230	New	June
	Yates – Line Creek 230 kV	17	602	230	New	June
	Yellowdirt – Dresden 230 kV	8	866	230	New	June
	Yellowdirt – Dresden 230 kV	8	866	230	New	June
	Yates – Lagrange 230 kV line	35	602	230	Rerate	April
	Yates – Lagrange 230 kV line	35	602	230	Rerate	April
	Autaugaville S.S. – County Line Road T.S.	15.7	865	230	New	May
	Autaugaville S.S. – County Line Road T.S.	15.7	865	230	New	May
	Clay T.S.	—	480	500 / 230	New	April
	County Line Road Loop In	1	502	230	New	May
	County Line Road T.S.	—	400	230 / 115	New	March
	E.Dalton Autobank Addition	—	300	230 / 115	Add 2nd Bank	June
	E.Point – Union City (Black & White)	23	656	230	Re-rate	June
	Enterprise – Sweatt	13.15	898	230	New	March
	Farley N.P. D.S.	—	25	230 / 13	New	April
	Gaston S.P. (Leeds line terminals)	—	796	230	Upgrade	April
	Hill St. – Wabash	2	602	230	Rerate	June
	Leeds T.S.(Gaston line terminals)	—	796	230	Upgrade	March
	Line Creek 230 / 115kV Sub.	—	400	230 / 115	New	June
	Miller S.P. – Clay T.S.	31.8	3,777	500	Conversion	June
	North Opelika Loop In	0.25	485	230	New	May
	North Opelika T.S.	—	400	230 / 115	New	May
	S. Bainbridge Series Reactor on Tallah. Tie Ln.	—	637	230	New	June
SERC – Southern	S. Hall 230 kV Sw'g Sta.	—	—	230	New	June
	Shoal Ck. 230 / 115 kV Sub.	—	300	230 / 115	New	June

Appendix 2: Transmission System Additions and Upgrades (230 kV and Above) March through September 2003

Region	Facility	Length Miles	N/E Capacity MVA	Voltage kV	Action	Expected Operating Date
SERC – VACAR	Lin # 255 North Anna to South Anna	31	796	230	Uprate	June
	Line # 2074 South Anna to Louisa	1.1	796	230	Uprate	June
	Line # 2088 Louisa to Gordonsville	0.5	796	230	Uprate	June
	Navy South substation	1	400	230	New	May
	Apex US1 Green Level	5.3	229	115	New	June
	Rocky Mount / Wilson	12.7	628	230	New	June
	Yemassee – Jasper County	37	960	230	New	September
	Rainey – Anderson #1	9.7	956	230	New	June
	Rainey – Anderson #2	9.7	956	230	New	June
SPP	LaCygne to Stilwell	31	1,972	345	Upgrade	July
WECC – AZ–NM–SNV	Phoenix – reconductor various lines	5	750	230	New	April
	Northwest – Arden	70	755	230	New	June
	West Phoenix – Rudd	14	1,200	230	New	June
	White Tanks – Rudd	6	1,200	230	New	June
	Shiprock – Four Corners	(8)	300	230	Replacement	June
	Shiprock – Four Corners	8	1,200	345	New	June
	Harry Allen – Northwest	30	2,787	500	New	June
	Rudd – Palo Verde	30	1,500	500	New	June
	Faulkner–Tolson	6	637	230	New	June
	Northwest Transformer Bank	—	1,500	500 / 230	New	March
	Avera Transformer Bank	—	300	230 / 138	New	June
	Harry Allen – Duke	4	907	500	New	April
	Rudd Transformer Bank	—	1,800	500 / 230	New	June
	Saguaro – Tortolita	1	625	500	New	June
WECC – CA–MX	Livermore – Pleasanton	3	1,421	230	New	May
	Newark – Metcalf	(28)	1,462	230	Replacement	May
	Newark – Los Esteros	14	1,462	230	New	May
	Los Esteros – Metcalf	14	1,462	230	New	May
	Los Esteros Transformer Bank	—	420	230 / 115	New	May
	Cortina Substation Transformer Bank	—	420	230 / 115	New	May
	Metcalf Transformer #13	—	1,122	500 / 230	New	May
	Metcalf Transformer #4	—	420	230 / 115	New	May
	Monta Vista Transformer #3	—	420	230 / 115	New	May
	Pittsburg Transformer #12	—	420	230 / 115	Replacement	May
	Tesla Transformer #6	—	1,122	500 / 230	New	June
	Imperial Valley Transformer Bank	—	1,120	500 / 230	Replacement	June
	Gold Hill Transformer Bank	—	420	230 / 115	Replacement	June

Appendix 2: Transmission System Additions and Upgrades (230 kV and Above) March through September 2003

Region	Facility	Length Miles	N/E Capacity MVA	Voltage kV	Action	Expected Operating Date
WECC – CA–MX	Lodi/Eight Mile Road – Stagg	1	1,421	230	Loop into station	June
	Ignacio Transformer Bank	—	420	230 / 115	New	May
WECC – CA–MX	TL23002 / TL23006 / TL23010 – San Luis Rey	1	1,462	230	Loop into station	April
WECC – NWPP	Meridian BC Reactor	—	150	230	New	April
	Warfield – Waneta	12	370	230	New	April
	Brilliant – K. Canal	12	339	230	New	April
	Green Valley – Smoky Hill	(29)	637	230	Replacement	April
	Green Valley – Spruce	19	637	230	New	April
WECC – RMPA	Spruce – Smoky Hill #1	10	637	230	New	April
	Tower – Smoky Hill	(16)	637	230	Replacement	April
	Tower – Spruce	6	637	230	New	April
	Spruce – Smoky Hill #2	10	637	230	New	April
	San Luis Valley Autotransformer	—	112	230 / 115	To be replaced	April
	San Luis Valley Autotransformer #1	—	150	230 / 115	New	April
	San Luis Valley Autotransformer #2	—	150	230 / 115	New	April

Definitions, Assumptions, and Abbreviations

How NERC Defines Reliability

NERC defines the reliability of the interconnected bulk electric system in two ways:

- 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.
- Operating Reliability — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Assumptions

In preparing its independent assessment, RAS reviewed the individual Regional self-assessments, although RAS did not independently verify the information contained in the individual Regional assessments in all cases. Summaries of supporting data are contained in Tables 1 and 2 and Figure 2. Additional supporting documentation is available through the Regional offices.

This assessment contains electricity supply and demand projections submitted by electric utilities through their Regional Councils for June 2003 through September 2003 and is based on several assumptions:

- Weather will be normal.
- Economic activity will occur as assumed in the demand forecasts.
- Generating and transmission equipment will perform at average availability levels.
- Generating units that are undergoing planned outages will return to service as scheduled.
- Generating unit and transmission additions and upgrades will be in service as scheduled.
- Demand reductions expected from direct control load management and interruptible demand contracts will be effective, if and when they are needed.
- Electricity transfers will occur as projected.

Abbreviations Used in This Report

AC	Alternating Current
AEP	American Electric Power
AP	Allegheny Power
AZ–NM–SNV	Arizona–New Mexico–Southern Nevada (Subregion of WECC)
CA–MX	California–Mexico (Subregion of WECC)
CAISO	California Independent System Operator
COI	California–Oregon Intertie
CP&L	Carolina Power & Light Company
DOE	Department of Energy (United States)
ECAR	East Central Area Reliability Coordination Agreement
EHV	Extra High Voltage
ERCOT	Electric Reliability Council of Texas
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability

FRCC	Florida Reliability Coordinating Council
HQ	Hydro–Québec
HVDC	High Voltage Direct Current
IDC	Interchange Distribution Calculator
IIPA	Integrated Independent Performance Assessment
IMO	Independent Electricity Market Operator (in Ontario)
IPP	Independent Power Producer
ISN	Interregional Security Network
ISO	Independent System Operator
ISO NE	New England Independent System Operator
kV	kilovolts (thousands of volts)
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MEN	MAAC-ECAR-NPCC
MET	MAIN-ECAR-TVA
MISO	Midwest Independent System Operator
MVA	Megavoltamperes
Mvar	Megavars
MW	Megawatts (millions of watts)
NEL	Net Energy for Load
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission (United States)
NUG	Non-Utility Generator
NWPP	Northwest Power Pool (Subregion of WECC)
NYISO	New York Independent System Operator
NYPP	New York Power Pool
OCSG	Operating Capability Study Group
OP-4	NEPOOL Operating Procedure 4 (Action During a Capacity Deficiency)
OPF	Optimal Power Flow
OTC	Operating Transfer Capability
PDCI	Pacific Direct Current Intertie
PJM	Pennsylvania-New Jersey-Maryland
RAS	Reliability Assessment Subcommittee
RCP	Reliability Coordination Plan
RMPA	Rocky Mountain Power Area (Subregion of WECC)
RMS	Reliability Management System
RTO	Regional Transmission Organization
SERC	Southeastern Electric Reliability Council
SMAIN	Southern MAIN

SPP	Southwest Power Pool
TIS	Transaction Information System
TLR	Transmission Loading Relief
TVA	Tennessee Valley Authority
TWh	Terawatthours (trillions of watt hours)
VACAR	Virginia and Carolinas (Subregion of SERC)
VAST	Virginia-AEP-Southern-TVA
VEM	VACAR-ECAR-MAAC
VP	Virginia Power
WECC	Western Electricity Coordinating Council
WUMS	Wisconsin-Upper Michigan

Reliability Assessment Subcommittee

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

Paul Johnson
ECAR Representative
Manager, East Bulk Transmission Planning
American Electric Power

Kent Saathoff
ERCOT Representative
Director of System Operations
Electric Reliability Council of Texas

John E. Odom, Jr.
FRCC Representative
Principal Engineer, RTO Development
Progress Energy Florida

Robert Snow
MAAC Representative
Director, Transmission Planning & Reliability
Public Service Electric and Gas

Christopher Plante
MAIN Representative
Director of Operations Analysis
Wisconsin Public Service Corporation

Hoa Nguyen
MAPP Representative
Power Supply Coordinator
Montana–Dakota Utilities Company

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

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

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

Jay Caspary
SPP Representative
Manager, Engineering
Southwest Power Pool

Kevin J. Dasso
WECC Representative
Director – Electric Trans. & Distribution Engineering
Pacific Gas & Electric Company

Dave Schoeberlein
DOE Liaison
Policy Analysis
U.S. Department of Energy

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

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

John Lawhorn
RTO Representative
Manager Reliability Engineering
Midwest Independent Transmission System Operator

Tom Hallam
FRCC Alternate
Staff Engineer
Florida Reliability Coordinating Council

Glenn P. Catenacci, PE
MAAC Alternate
Staff Engineer
Public Service Electric and Gas

Edward R. Riley
WECC Alternate
Director of Regional Coordination
California Independent System Operator

Jeffrey L. Mitchell
ECAR Alternate
Manager, Transmission Services
East Central Area Reliability Coordination Agreement

Robert W. Cummings
NERC Staff Coordinator
North American Electric Reliability Council