NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2007 SUMMER ASSESSMENT

The Reliability of the Bulk Power System in North America

May 2007

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INTRODUCTION

Mission of the North American Electric Reliability Corporation (NERC)

NERC's mission is to improve the reliability and adequacy of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses and reports on future adequacy; evaluates owners, operators, and users for reliability preparedness; educates, trains and certifies industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants.

NERC is subject to oversight by the United States of America's (U.S.) Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. Further, in the U.S., NERC has legal authority as of June 4, 2007 to enforce reliability standards on all owners, operators, and users of the bulk power system, rather than relying on voluntary compliance. NERC is working to gain similar recognition by governmental authorities in Canada, including eight provinces and the National Energy Board, before the end of this year, and will seek recognition in Mexico once the necessary legislation is adopted there.

Section 39.11(b) of the United States of America's FERC's regulations provide that: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission," but Section 215 of the Federal Power Act also withholds authority from the Electric Reliability Organization to order construction of additional generation or transmission or to adopt enforceable standards that would have that effect. The *2007 Summer Assessment* is part of NERC's response to this regulation.

How This Assessment is Prepared

NERC, through the Reliability Assessment Subcommittee (RAS) of the NERC Planning Committee (PC), prepared this *2007 Summer Assessment* based on data and information provided by the eight regional reliability organizations. The *2007 Summer Assessment* report's summary represents NERC's independent judgment of the reliability and adequacy of the bulk power system in North America for the upcoming summer peak demand period. NERC's role is to spotlight areas of concern. Specific actions and solutions to resolve the issues are reserved for others.

The assessment was prepared by conducting a peer review of the regional self assessments coupled with NERC staff's independent evaluation. The Reliability Assessment Subcommittee and NERC's staff reviewed regional summaries of projected peak electric demand and capacity resources; appraised regional plans for new electric generation resources and transmission facilities due to be in service for the summer; and evaluated expected operating conditions. Neither NERC, nor the subcommittee makes any projections or draws any conclusions in this report regarding expected electricity prices for the assessment period.

Additional supporting documentation is available through NERC and the regional reliability organizations. While the Reliability Assessment Subcommittee and NERC's staff did not independently verify all of the information contained in the individual regional self-assessments, it did investigate and verify information where conflicts were present. Summaries of the supporting data are contained in the tables and figures throughout the report.

This assessment contains electricity supply and demand projections for June 2007 through September 2007 and is based on several assumptions:

- Normal summer peaking weather will occur.
- Economic activity will occur as assumed in the demand forecasts.
- Generating and transmission equipment will perform at historical availability levels.
- Generating units that are undergoing planned outages will return to service as scheduled.
- Generating unit and transmission system 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.
- Other demand response programs reducing peak demands are included in peak demand forecasts.
- Electricity transfers will occur as projected.

While NERC prepares the overall seasonal assessment, it is the task of the individual regional reliability organizations to ensure their members comply with NERC reliability requirements and have procedures in place to deal with conditions that are outside the bounds of the assumptions underlying this report. Reliability regions generally run sensitivity analyses on various scenarios to develop operating procedures in preparation for potential unexpected conditions in the upcoming summer.

Assessment Summary

Extreme weather was experienced across much of North America in the summer of 2006. Record peak demands depleted available resources, which necessitated the implementation of pre-planned emergency procedures in some areas to maintain a balance between available supply and demand. Emergency alerts, public appeals, voltage reductions, and shedding interruptible customer load were used to various degrees during the last week of July and the first week of August. The only interruptions of firm customer load occurred due to heat-related problems on distribution systems, but these had no effect on the bulk power system.

If extreme weather is experienced in the summer of 2007, and supplies become limited, emergency operating procedures similar to those used in 2006 are available.

Improvements Made Since 2006 Summer to Improve Reliability

Several issues highlighted in NERC's Long-term Reliability Assessment issued in October 2006 are being addressed. The amount of demand represented by customer Interruptible Demand and Direct Control Load Management programs increased since last year by more than 10 percent in Florida, 13 percent in other parts of the southeastern United States, and almost 20 percent in the western United States and Canada. Many regions are studying the interdependence of fuel delivery and reliability, and improving coordination between fuel suppliers and generators.

Regions with improved conditions since last summer include:

- The Southeast, where utilities invested more than $1.21 billion in transmission in 2006.
- Boston, where the ability to import electricity has been boosted by 1,000 megawatts due to two new 345 kV transmission lines running from Stoughton, Mass., into Boston, which became operational in October 2006 and May 2007 respectively.
- Southwestern Connecticut, which can import 230 more megawatts of electricity since a 345 kV transmission line from Bethel to Norwalk was put into service in October 2006.
- Texas, which has reduced its transmission congestion, allowing it to reduce the number of less-efficient generating units that must run in tight reliability situations from 7 to 1.

Sustained Extreme Weather Could be a Threat to Supply Adequacy. Procedures are in Place to Ensure Reliable Operation of the Grid under Most Conditions

Forecasts of performances in this assessment are based on normal weather with a 50% chance of being higher or lower than expected. Last summer's wide-spread, sustained extreme weather (high temperature, high humidity) caused demands to exceed forecast by over 3%. As a result, the 50/50 forecast for 2007 is about 1% less than the 2006 actual demand. If similar extreme weather occurs this summer, it could be a threat to resource supply adequacy. Some of the primary extreme weather impacts are:

- Higher loads and imports driven by cooling demands require static/dynamic reactive support

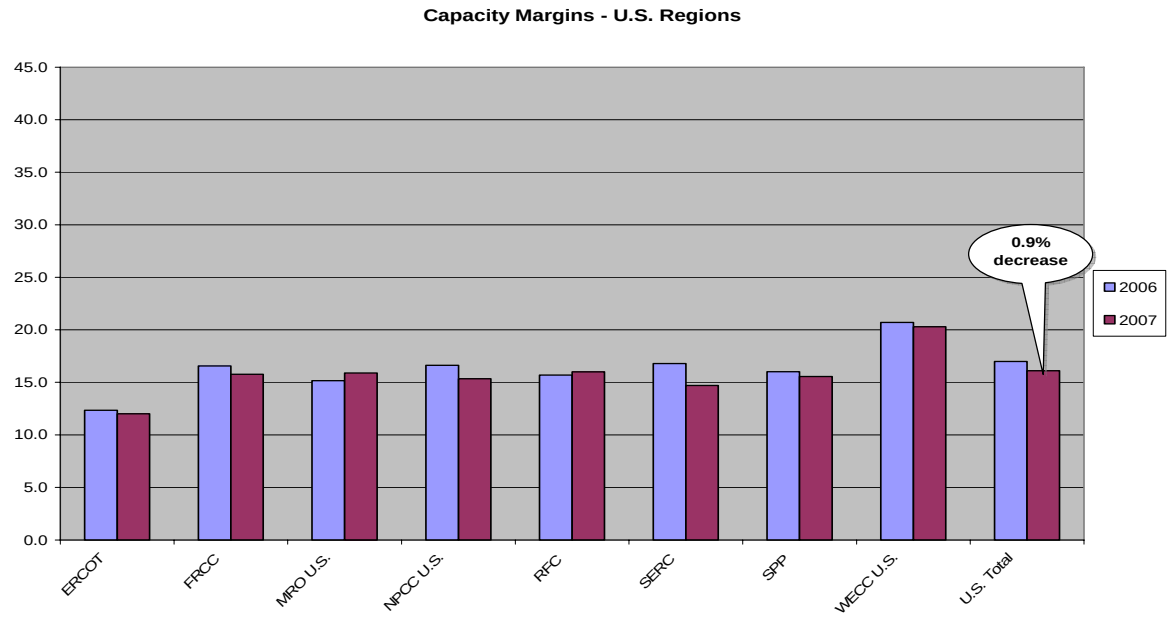
- Fossil-fired/Combustion Turbine units can be de-rated due to air/water temperature cooling capability and also may experience higher forced outage rates
- Bulk power system thermal limits may be reduced and substation/distribution equipment can experience higher failure rates
- Run-of-river hydro and wind generation capacity may be reduced

Emergency operating procedures are available to maintain a balance between supply and demand to ensure the reliability of the bulk power system[1] when it is stressed. Many regions study extreme weather condition cases to understand and manage the associated risks.

Capacity Margins for the Summer 2007 are Comparable to 2006

The capacity margins projected for the summer of 2007 are comparable to 2006 and similar performance is expected overall. Capacity margins are intended to mitigate the higher load levels associated with extreme weather events, the unplanned loss of generation capacity, and provide sufficient operating margins. Figure 1 shows the capacity margins (committed generation versus load). Comparing summers of 2007 and 2006, U.S. reported a 0.9% drop in projected capacity margins and Canada a 0.9% increase.

Figure 1a: Change in U.S. Regional Projected Capacity Margins From 2006 to 2007



[1] NERC assessments focus exclusively on bulk power systems; i.e., no review of extreme weather effects on distribution systems

Figure 1b[2]: Change in U.S. Subregional Projected Capacity Margins From 2006 to 2007

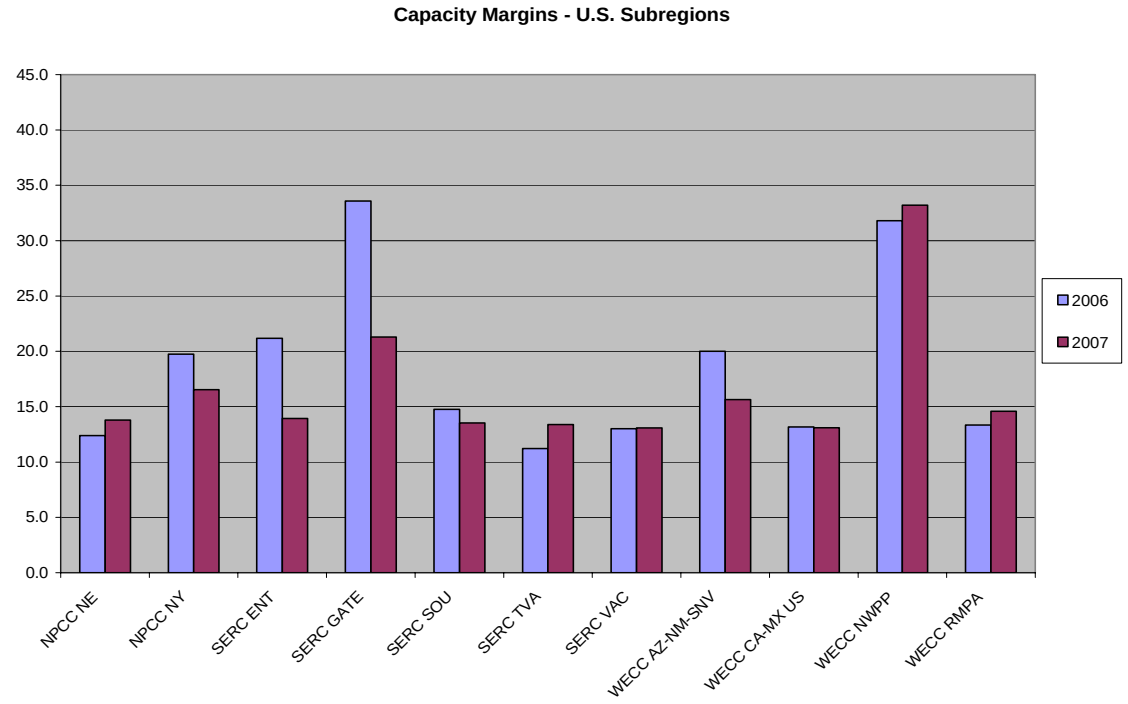
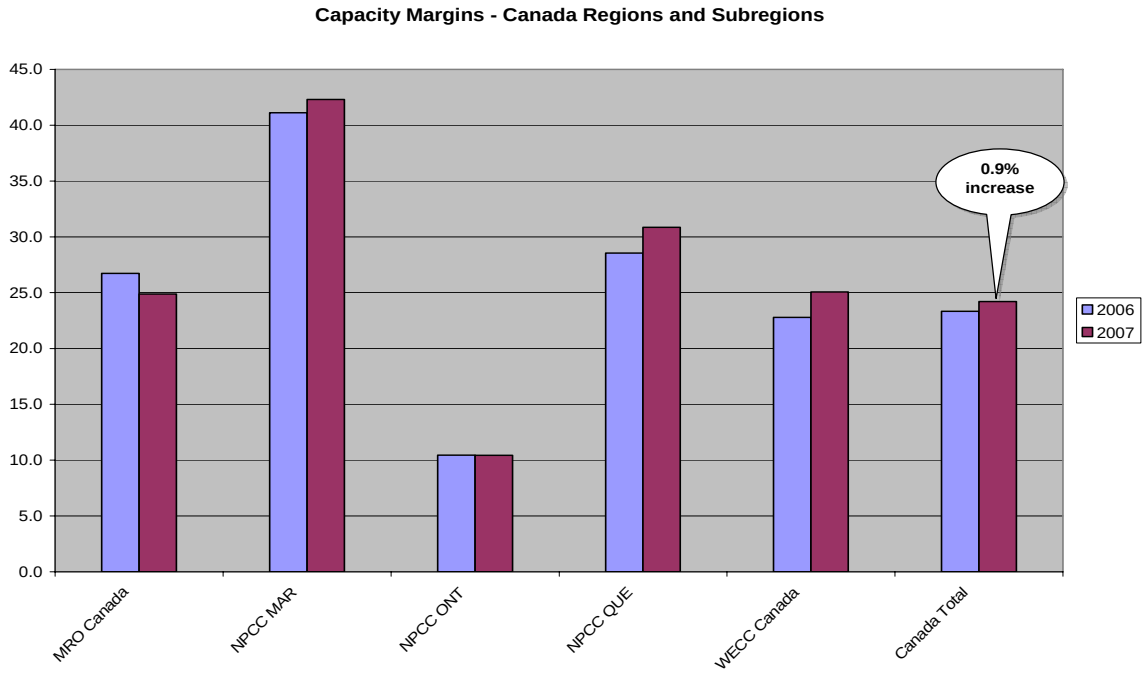


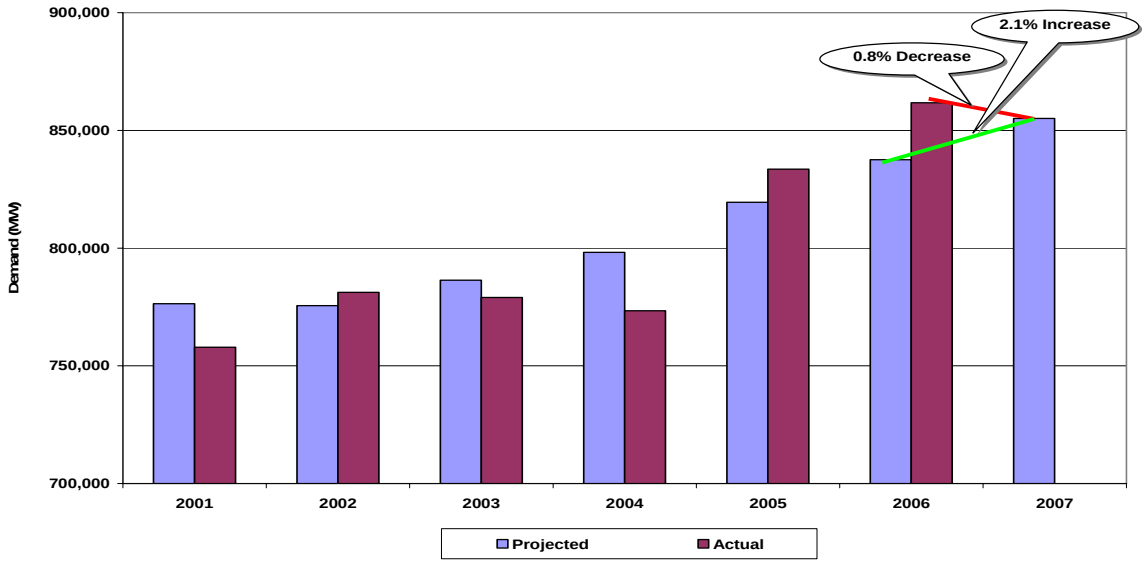
Figure 1c: Change in Canadian Projected Capacity Margins From 2006 to 2007



[2] The capacity margins for SERC-Entergy and SERC Gateway subregions are notably different in the summer of 2007 compared to 2006 because some generation previously reported as committed in is now considered uncommitted.

Figure 2 summarizes a forecasted 2007 summer demand growth of 2.1% for normal weather conditions compared to the 2006 forecast. Extreme summer weather experienced across much of North America in 2006 drove actual peak demand 3.1% higher than forecast. Overall, the 2007 summer forecast demand assuming normal weather is 0.8% lower than the 2006 actual summer demand reflecting extreme weather. Percent changes from 2006 actual to 2007 forecast are: ERCOT: +2.3%, FRCC: +2.5%, MRO: +6.6%, NPCC: -1.7%, RFC: -3.9%, SERC: +0.4%, SPP: +0.1% and WECC: -2.1%.

Figure 2[3]: Year-on-Year Comparison of Summer Projected Total & Actual Demand



Reliability in Southern California, Connecticut and Boston

NERC expects the ***Southern California*** area to have lower 2007 summer capacity margins than most areas, requiring significant amounts of imported power and, therefore, heavily loaded transmission lines into this area much of the time.

The California Independent System Operator (CAISO) has studied[4] a number of operating reserve margin[5] scenarios, including extreme weather conditions increasing demand. Procedures have been developed by the CAISO to implement demand response procedures and curtail interruptible loads to maintain required operating reserves in Southern California. If extreme

[3] NERC currently does not collect data on demand response programs for the previous year's actual demand. Therefore, the comparison of 2006 actual and 2007 forecasted demand does not account for Direct Control Load Management and Interruptible Demand programs that may have reduced demand during the 2006 summer heat wave and would further increase the difference between the 2006 actual peak and the 2007 forecasted demand.

[4] http://www.caiso.com/1b95/1b95abb649df4.pdf?ht=2007%20assessment%202007%20assessment%202007%20assessment%202007%20assessment

[5] See NERC's Glossary for definition, ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_01Nov06.pdf

weather and loss of generating resources occur simultaneously, the CAISO may also need to shed firm load to balance resources and demand.
The CAISO analyzed the probability of implementing actions during these events to meet operating reserve margins. There is a 14% probability of using demand response programs, which are triggered when operating reserve margins fall to the 7% range, and a 4.6% probability using interruptible load programs, which are triggered when operating reserve margins drop to less than 5%. There is less than 3% probability of firm load shedding, which triggered when operating reserve margins decline to 3% or below, which could occur should both extreme weather and a system contingency occur at the same time.

The transmission network into and within ***Southwest Connecticut*** (SWCT) has historically faced reliability concerns. The outlook for the area has improved for the summer of 2007 with the October 2006 addition of Phase 1 of the 345 kV Southwest Connecticut Reliability Project increasing the import capability. Therefore the combined ability of the electric generating resources and the available transmission capacity to import electric energy in the area should be adequate to meet the demand under normal and most extreme weather conditions.

Resource adequacy studies[6] show ***Greater Connecticut*** is a major load pocket that has an immediate need for resources, transmission improvements, or both. The projected capacity margin for the summer is expected to remain negative. Over 200 MW of Demand Response resources in Connecticut have been added, which will help to meet the area's summer 2007 resource needs. If local resources and imports into Connecticut are insufficient to meet the need, system operators would rely on the implementation of Operating Procedure No. 4, *Action During a Capacity Deficiency* in Greater Connecticut to maintain local and regional system reliability.

Reliability of the ***Boston*** area, a major demand center in New England, has been a concern. The NSTAR 345 kV Transmission Reliability Project focuses on increasing the import capability into the area. In Stage 1, the NSTAR 345 kV cable became operational in October 2006. The second cable was energized in May 2007 increasing the transmission import capability into the Boston area by approximately 1,000 MW (to 4,600 MW total). Currently, a positive summer 2007 capacity margin is forecasted for the Boston area, a direct result of the NSTAR project.

Flooding Forecasted in British Columbia Could Impact System Reliability

British Columbia's provincial Ministry of Environment (MoE) River Forecast Center reports all areas of the province continue to have above or well above normal snow packs. Any extended period (5+ days) of well above normal temperatures, and/or a period of heavy rainfall during the spring (generally mid-May to mid-June) will be sufficient to produce high river flows and likely flooding in some areas. If flooding should occur, the potential for impacts are likely to be widespread and significant, given the distribution of heavy snow packs. The flooding could impact areas from the U.S. border, up through the central interior and into the north-west and north-east.

[6] http://www.iso-ne.com/trans/rsp/2006/rsp06_final_public.pdf.

British Columbia Transmission Corporation (BCTC) is responsible for the protection of substations and transmission structures and is taking the following actions to ensure their security and service reliability:

- Coordinating with BC Hydro to ensure a continued supply of safe and reliable electricity to British Columbia residents in the event of floods due to melting snow pack.
- Completing a corporate communication plan working with all levels of government, the communities and other vital utilities in the event of a flood.
- Protecting substations from flood damage. This includes, but not limited to, risk identification, equipment relocation, special equipment acquisition, and staff emergency training and exercises.
- Implementing a recovery plan dealing with adverse transmission system effects from floodwaters.
- Establishing programs to maximize the ability for employees to work during a flood.

Other Items

Industry Investments Focused on Reliability — All regional reliability organizations have seen increased investment by their members in the bulk power system reliability improvements:

- Reduced need for Reliability Must Run (RMR) units in some regions
- Upgrading existing and adding new generating/transmission facilities
- Deployment of Demand Response programs

Amplified Understanding of the Fuel and Electric Delivery System Interdependency — Many regions have initiated studies on gas and coal deliverability to understand potential risks and to develop operational plans. These analyses support energy security and higher coupled delivery system reliability.

Increased Wind Generation can Influence Transmission Loading Volatility — Wind generation in Texas, Minnesota, and the Dakotas can influence the volatility and reduce the predictability of transmission flows and has resulted in development of new operational guidelines to support their system integration. Several regional reliability organizations and their members are performing wind integration studies to increase the potential benefits and ensure reliable operation and delivery.

Hydro-electric Reservoirs are lower than Normal — Overall, U.S. hydro-electric reservoirs are lower than normal, but can adequately serve peak demands. The lower water levels can impact off-peak reliability, though this situation will be managed through operating procedures in all regions.

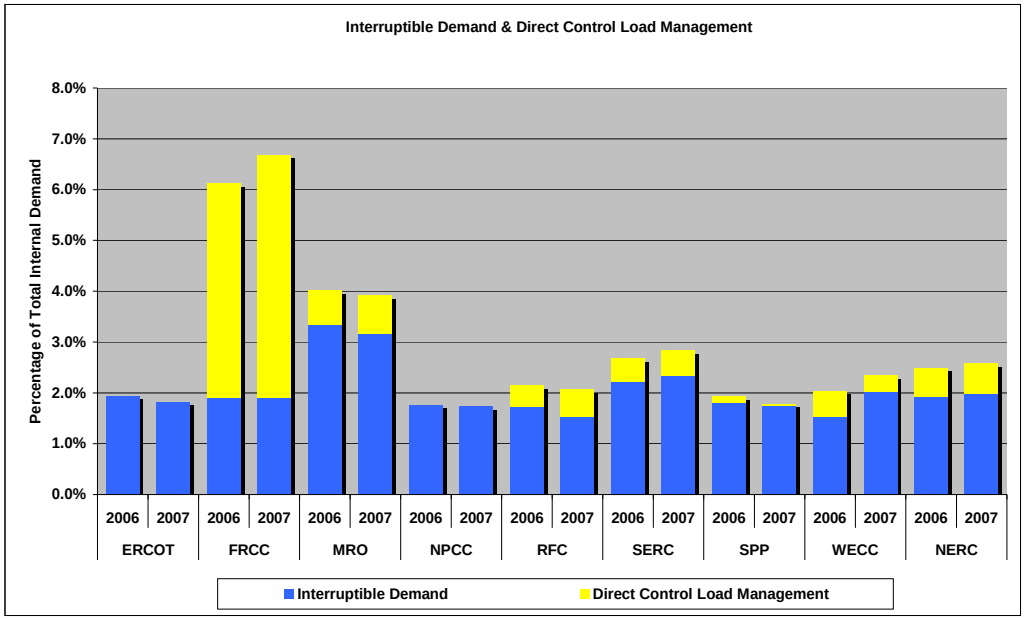
Overall Increase in Interruptible Demand and Direct Control Load Management Programs — These specific programs directly empower operators to interrupt load to support operational reliability requirements. NERC-wide application of these specific Demand Response programs has increased by 5.8% (about 1,200 MW) from the 2006 Summer Assessment (Figure 3), which

helps support resource adequacy. FRCC is the largest user of Direct Control Load Management as their members deploy these programs on control of air conditioners.

There are five primary reasons for the percentage decreases in Interruptible Demand and Direct Control Load Management in some regions between the summers of 2006 and 2007:

1. 95% confidence levels analysis was used to forecast the available demand response capacity during peak in 2007 rather then demand response capacity in 2006 (ERCOT)
2. The comparison is based on demand response as a percent of total demand. If demand response grows slower than total demand growth, the percentage decreases, though the total amount of demand response increased (MRO)
3. Realignment of regional reliability organization members (RFC & SERC)
4. Customers decide not to continue their participation in these programs (NPCC)
5. Data correction (SPP)

Figure 3: Comparison of Interruptible Demand and Direct Control Load Management



Enhancements to Future NERC Assessments

This summer assessment is based on comparing projected margins with each region's specific criteria. These regional and sub-regional criteria vary reflecting the unique character of generation, load, and transmission. For example, the Pacific Northwest[7] is an "energy limited" area and capacity margins or loss-of-load-expectation (LOLE) analysis are not meaningful measures of resource adequacy for this area. NERC is developing a standard on resource adequacy assessment that should provide a more comparable basis for resource adequacy assessments in the future.

Enriching data collection and analysis will broaden NERC's ability to perform more in-depth seasonal reliability assessments. Some of the enhancements under consideration are:

- Comparable Adequacy Assessment evaluation processes enhancing year-on-year comparisons
- Retrospective assessments comparing actual summer conditions to forecast.
- Intra- and Inter- area oscillation analysis measuring small signal stability margins
- Multiple contingencies analysis quantifying the impact of these events on adequacy
- Static and dynamic reactive resource adequacy to support load pockets and maintain voltage stability margins. Further, define what qualifies as "Load Pockets" for this analysis
- Demand Response programs which influence reliability
- Increased scenario evaluation:
    - Assessments of year-on-year influence of Green House Gas (CO_2) regulation and Renewable Energy Mandates on bulk power system reliability/adequacy
    - Large, rural demand development resulting from ethanol refinement
    - Fuel supply deliverability
    - Transmission & Generation Delays

[7] For example, see NWPP http://www.nwpp.org/pdf/Summer%20Assessment%202006.pdf

Regional Highlights

ERCOT

Continuing strong economic and population growth in Texas is reflected in the 2007 peak demand forecast of 63,792 MW, which is 2.3% increase over the all-time actual peak of 62,339 MW in 2006. While market participants in the region added approximately 1,200 MW of net dependable resources, ERCOT's reserves this summer will be slightly lower than last summer but above the 12.5% target reserve margin this summer.

ERCOT has eliminated all but one Reliability Must Run agreement through aggressive transmission planning and expansion programs. As a result, transmission congestion is not expected to be a reliability concern for the ERCOT region. No unusual operating conditions that would impact system reliability are expected this summer, and ERCOT is working on a new Emergency Interruptible Load Service as an new tool for operators in the event reserves are depleted and in order to avoid interruption of firm demand during system-wide emergencies.

Although projected available resources this summer will meet ERCOT's adequacy criteria, they are expected to be close to the minimum required by the criteria. An extremely hot summer that results in load levels significantly above forecast, higher than normal unit forced outage rates, or financial difficulties of some generation owners that may make it difficult for them to obtain fuel from suppliers are all risk factors that alone or in combination could result in inadequate supply. In the event that occurs, ERCOT will implement its Emergency Electric Curtailment Plan (EECP) (See Section 5.6.6.1 of the ERCOT Protocols[8]). The EECP includes procedures for use of interruptible load, voltage reductions, procuring emergency energy over the DC ties and load shedding to avoid system collapse.

FRCC

Transmission constraints in the Central Florida area may require remedial actions depending on system conditions. However, remedial operating strategies have been developed and will continue to be evaluated to ensure system reliability.

MRO

The region's reserve margin improved slightly with the addition of a new 790 MW coal-fired base-load unit in Iowa. This new generation and its related transmission facilities improve east to west power transfers across Iowa, although north to south power transfers continue to be a concern.

In Nebraska, all transmission lines damaged by the December 2006 severe ice storms are back in service. In different parts of the region, transmission investments are being made, and MRO's transmission system is expected to perform reliably for the summer 2007.

[8] http://www.ercot.com/mktrules/protocols/current.html

NPCC

In the three sub-areas of NPCC which are summer peaking, New York, New England and Ontario margins are improved when compared with the summer of 2006. All NPCC sub-regions expect sufficient resources to be available to meet projected demands during the 2007 summer.

Québec and the Maritimes are predominately winter peaking Areas and therefore adequate resources, including the supply for firm external sales, are expected to be available. Adequate transfer capability exists to transmit surplus resources from these sub-regions to the others; however, a certain amount of bottling of resources from Québec and the Maritimes to the rest of NPCC is normal and expected.

The larger generation additions within the NPCC sub-regions that have been placed in service since the summer of 2006 include: the 100 MW Maple Ridge Wind Phase 2 Project and the 95 MW uprate of the Ginna Nuclear Plant in New York, about 190 MW of wind capacity in Ontario, three units at the Eastmain-1 Generating Station (480 MW) in Québec and the TransCanada Energy natural gas Generating Station (507 MW) in Québec. Phase One of the Goreway gas-fired station (485 MW) in Ontario is scheduled to go into service for the summer. Some smaller size additions are discussed in the sub-region sections.

Major transmission additions for 2007 summer include: first stage of the NSTAR 345 kV Reliability Project that involves the addition of two new 345 kV underground cables from Stoughton, Massachusetts into the Boston area (The first cable was energized in the autumn of 2006; the second cable was energized in May of 2007.), the Plumtree-Norwalk 345 kV circuit in southwest Connecticut (went into service), a new 345 kV line in Vermont that is a portion of the Northwest Vermont Reliability Project (in service), the 660 MW Neptune HVDC Cable that extends between PJM and Long Island (planned for the summer of 2007), a new Mott Haven 345 kV substation in New York City serving load in the Bronx, between Dunwoodie and Rainey substations (planned for the summer of 2007), upgrades in the Rochester, NY vicinity (planned for the summer of 2007), the 735/315 kV 1,100 MVA transformer at Arnaud Transformer Station in Québec (in service) and a 345 MVAR 315-kV capacitor bank at the Hertel 735/315-kV substation in the Montreal area (in service). These should all provide significant system reliability improvements.

As discussed above in the Assessment Summary section, some areas of concern exist in Connecticut and Massachusetts due to transmission/resource constraints.

RFC

The Reliability*First* region expects the capacity resources and the transmission system to be adequate for the expected operating conditions during the summer of 2007. Capacity margins are comparable to those projected for 2006 summer. It is expected that generation re-dispatch, the NERC Transmission Loading Relief (TLR) procedure and operator intervention will be necessary, at times, to mitigate contingencies and reduce loading of certain critical flowgates. These procedures and actions are well understood by the system operators and will be used as needed to maintain transmission reliability.

The addition of significant transmission and distribution capacitors that affect Washington, D.C. has improved reliability in that area over last summer. Although generation from the Potomac River plant in Washington D.C. is restricted due to environmental regulation, it is available for system emergencies.

SERC

SERC has had significant merchant generation development in the latter half of the 1990s and early 2000s. Much of this merchant generation has not been contracted to serve load within SERC and its deliverability is not assured. Over 260,000 MW of generating capability is expected to exist and be connected this summer, exceeding the forecast summer total peak demand by over 60,000 MW or 30%.

SERC members invested approximately $1.21 billion in new transmission lines and system upgrades (includes transmission lines 100 kV and above and transmission substations with a low-side voltage of 100 kV and above) in 2006. They plan to invest approximately $1.53 billion in 2007 and $1.71 billion in 2008.

SPP

Capacity margins in SPP are forecast to be slightly less than those for 2006 Summer, but still exceed the target margin level. SPP will continue to monitor line loadings on 115-161 kV lines around NW Arkansas. Since last year, the SPP has added about 30 miles of new EHV transmission lines to improve reliability in SPP footprint. Also, this will be the first summer since SPP has launched its Energy Imbalance Services Market (EIS) in February 2007.

WECC

The aggregate WECC 2007 summer total internal demand is forecast to be 157,075 MW (U.S. systems 137,552 MW, Canadian systems 17,426 MW, and Mexican system 2,097 MW). The forecast is based on normal weather conditions and is 2.1% below last summer's actual peak demand, which was established under generally above normal to well above normal temperatures in the region. Weather sensitivity analyses indicate that summer peak demands may increase by as much as 4,200 MW, assuming a one in ten year heat wave. Such a heat wave would reduce the region's capacity margin to 18.4% and the reserve margin to 23.1%.

Southern California relies on significant amounts of imported power and the transmission into that area will be heavily loaded. The transmission system is considered adequate for all projected firm transactions but has limited ability to support unusually large amounts of economy energy transfers. Reactive reserve margins are expected to be adequate for expected peak load conditions. Close attention to maintaining appropriate voltage levels is expected to prevent voltage problems. The 2007 summer peak demand forecast for California is 58,925 MW or 7.3% below last summer's actual peak demand of 63,572 MW. The area's 2006 summer peak demand occurred during a period of unusually hot weather. The forecast peak demand includes 2,671 MW of interruptible demand and load management. The projected capacity margin for the peak month is 13.3%, excluding uncommitted resource additions of 185 MW.

Extreme weather conditions, which can significantly increase demand, or the sudden unplanned loss of large amounts of resources, would require the California Independent System Operator (CAISO) to implement demand response procedures and curtail interruptible loads to maintain required operating reserves in Southern California. If extreme weather and loss of resources occur simultaneously, the CAISO may also need to shed firm load to balance resources and demand. The CAISO analyzed the probability of implementing actions during these events to meet operating reserve margins. There is a 14% probability of utilizing demand response programs if operating reserves fall to 7% during a heat storm or a system contingency, and a 4.6% probability utilizing interruptible load programs if reserves drop to 5% for either of these events. There is a 2.9% probability of firm load shedding being initiated if reserves decline to 3% should both extreme weather and a system contingency occur at the same time.

Broader Inter-Regional Reliability Organization Cooperation

The regional reliability organizations and their members have begun implementing coordination arrangements supporting reliability assessment throughout North America. For example, the Transmission Owner/Operators Forum (TOOF) has gathered North American organizations concentrated on sharing reliability management practices.

Further, a number of inter-regional reliability assessments have been incorporated under the umbrella of the recently formed Eastern Interconnection Reliability Assessment Group (ERAG) to replace individual interregional groups. With the consolidation of three of the former NERC Regions (ECAR, MAAC, and MAIN) into one (ReliabilityFirst Corp.), the ERAG established three study forums to replace five forums consisting of NPCC-RFC (replacing MEN), RFC-SERC East (replacing VEM), and MRO - RFC - SERC West (replacing TVA, Entergy, Gateway) – SPP (replacing MET, MMS, and MSW). Prior to each summer and winter season, these forums will conduct interregional transmission studies and produce adequacy/reliability assessment reports for the upcoming peak seasons.

Summer 2007 Resources, Demands, and Margins[9]

Projected resources and margins shown in Tables 1a–d below do not reflect any possible fuel supply/delivery or hydro limitations.

Table 1a: Estimated June 2007 Summer Resources, Demands, and Margins

June 2007	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	W/O Uncommitted Available Capacity Margin (%)	With Uncommitted Potential Capacity Margin (%)
United States					
ERCOT	56,834	71,179	0	20.2	20.2
FRCC	42,097	50,772	1,146	17.1	18.9
MRO	39,312	49,277	0	20.2	20.2
NPCC	59,979	70,851	0	15.3	15.3
New England	26,532	30,775	0	13.8	13.8
New York	33,447	40,076	0	16.5	16.5
RFC	169,500	213,822	5,300	20.7	22.6
SERC	180,851	227,187	36,308	20.4	31.4
Entergy	24,730	31,716	13,666	22.0	45.5
Gateway	17,022	24,059	8,974	29.2	48.5
Southern	44,396	54,290	6,540	18.2	27.0
TVA	38,300	47,623	4,234	19.6	26.1
VACAR	56,403	69,499	2,894	18.8	22.1
SPP	38,272	49,552	9,758	22.8	35.5
WECC	123,073	164,873	85	25.4	25.4
AZ-NM-SNV	27,839	35,381	0	21.3	21.3
CA-MX US	51,374	64,106	85	19.9	20.0
NWPP	33,412	52,595	0	36.5	36.5
RMPA	10,448	12,760	0	18.1	18.1
Total-United States	**709,918**	**897,513**	**52,597**	**20.9**	**25.3**
Canada					
MRO	5,643	7,342	100	23.1	24.2
NPCC	48,494	64,224	0	24.5	24.5
Maritimes	3,058	5,097	0	40.0	40.0
Ontario	23,949	27,773	0	13.8	13.8
Quebec	21,487	31,354	0	31.5	31.5
WECC	16,858	21,727	0	22.4	22.4
Total-Canada	**70,995**	**93,293**	**100**	**23.9**	**24.0**
Mexico					
WECC CA-MX Mex	1,953	2,387	0	18.2	18.2
Total-NERC	**782,866**	**993,193**	**52,697**	**21.2**	**25.1**

[9] See notes to Tables 1a, 1b, 1c and 1d. Uncommitted generation may not be deliverable. Potential capacity margins assume it is.

Table 1b: Estimated July 2007 Summer Resources, Demands, and Margins

July 2007	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	W/O Uncommitted Available Capacity Margin (%)	With Uncommitted Potential Capacity Margin (%)
United States					
ERCOT	60,166	71,244	0	15.5	15.5
FRCC	42,686	52,025	1,146	18.0	19.7
MRO	41,537	49,391	0	15.9	15.9
NPCC	59,979	71,074	0	15.6	15.6
New England	26,532	30,791	0	13.8	13.8
New York	33,447	40,283	0	17.0	17.0
RFC	179,600	213,792	5,300	16.0	18.0
SERC	194,953	228,588	36,455	14.7	26.4
Entergy	26,193	31,690	13,666	17.3	42.3
Gateway	18,820	23,914	8,974	21.3	42.8
Southern	48,160	55,699	6,540	13.5	22.6
TVA	41,221	47,614	4,234	13.4	20.5
VACAR	60,559	69,671	3,041	13.1	16.7
SPP	41,838	49,552	9,758	15.6	29.5
WECC	134,176	168,334	125	20.3	20.4
AZ-NM-SNV	30,086	35,660	0	15.6	15.6
CA-MX US	56,741	65,339	125	13.2	13.3
NWPP	35,803	53,611	0	33.2	33.2
RMPA	11,546	13,517	0	14.6	14.6
Total-United States	**754,935**	**904,000**	**52,784**	**16.5**	**21.1**
Canada					
MRO	5,641	7,616	100	25.9	26.9
NPCC	49,638	65,158	0	23.8	24.0
Maritimes	3,068	5,620	0	45.4	45.4
Ontario	24,964	27,872	0	10.4	11.1
Quebec	21,606	31,666	0	31.8	31.8
WECC	17,127	22,170	0	22.7	22.7
Total-Canada	**72,406**	**94,944**	**100**	**23.7**	**24.0**
Mexico					
WECC CA-MX Mex	2,097	2,562	0	18.1	18.1
Total-NERC	**829,438**	**1,001,506**	**52,884**	**17.2**	**21.3**

Table 1c: Estimated August 2007 Summer Resources, Demands, and Margins

August 2007	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	W/O Uncommitted Available Capacity Margin (%)	With Uncommitted Potential Capacity Margin (%)
United States					
ERCOT	62,682	71,244	0	12.0	12.0
FRCC	43,824	52,025	1,146	15.8	17.6
MRO	40,813	49,371	0	17.3	17.3
NPCC	59,979	71,065	0	15.6	15.6
New England	26,532	30,782	0	13.8	13.8
New York	33,447	40,283	0	17.0	17.0
RFC	178,000	213,820	5,300	16.8	18.8
SERC	193,293	228,601	36,455	15.4	27.1
Entergy	27,249	31,657	13,666	13.9	39.9
Gateway	18,127	23,947	8,974	24.3	44.9
Southern	48,099	55,707	6,540	13.7	22.7
TVA	40,405	47,614	4,234	15.1	22.1
VACAR	59,413	69,676	3,041	14.7	18.3
SPP	41,774	49,552	9,758	15.7	29.6
WECC	132,685	168,021	215	21.0	21.1
AZ-NM-SNV	29,323	35,650	0	17.7	17.8
CA-MX US	56,834	65,404	185	13.1	13.3
NWPP	35,521	53,867	30	34.1	34.1
RMPA	11,007	12,901	0	14.7	14.7
Total-United States	**753,050**	**903,699**	**52,874**	**16.7**	**21.3**
Canada					
MRO	5,728	7,625	100	24.9	25.9
NPCC	48,978	64,900	0	24.5	24.5
Maritimes	3,038	5,617	0	45.9	45.9
Ontario	24,171	27,797	0	13.0	13.0
Quebec	21,769	31,486	0	30.9	30.9
WECC	17,128	22,859	0	25.1	25.1
Total-Canada	**71,834**	**95,384**	**100**	**24.7**	**24.8**
Mexico					
WECC CA-MX Mex	2,091	2,554	0	18.1	18.1
Total-NERC	**826,975**	**1,001,637**	**52,974**	**17.4**	**21.6**

Table 1d: Estimated September 2007 Summer Resources, Demands, and Margins

September 2007	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	W/O Uncommitted Available Capacity Margin (%)	With Uncommitted Potential Capacity Margin (%)
United States					
ERCOT	49,490	71,325	0	30.6	30.6
FRCC	41,895	50,403	1,146	16.9	18.7
MRO	37,549	48,367	0	22.4	22.4
NPCC	53,138	67,576	0	21.4	21.4
New England	24,332	30,070	0	19.1	19.1
New York	28,806	37,506	0	23.2	23.2
RFC	154,700	211,898	5,300	27.0	28.8
SERC	175,016	226,070	36,455	22.6	33.3
Entergy	23,856	31,637	13,666	24.6	47.3
Gateway	16,571	24,074	8,974	31.2	49.9
Southern	43,185	54,102	6,540	20.2	28.8
TVA	38,157	46,822	4,234	18.5	25.3
VACAR	53,247	69,435	3,041	23.3	26.5
SPP	36,440	49,552	9,758	26.5	38.6
WECC	121,408	166,677	235	27.2	27.3
AZ-NM-SNV	27,152	35,511	0	23.5	23.5
CA-MX US	52,254	64,575	205	19.1	19.3
NWPP	32,025	54,305	30	41.0	41.1
RMPA	9,977	12,200	0	18.2	18.2
Total-United States	**669,636**	**891,868**	**52,894**	**24.9**	**29.1**
Canada					
MRO	5,369	7,400	100	27.4	28.4
NPCC	46,999	63,371	0	25.8	25.8
Maritimes	3,178	5,508	0	42.3	42.3
Ontario	22,071	26,385	0	16.4	16.4
Quebec	21,750	31,478	0	30.9	30.9
WECC	16,909	22,088	0	23.4	23.4
Total-Canada	**69,277**	**92,859**	**100**	**25.4**	**25.5**
Mexico					
WECC CA-MX Mex	1,998	2,441	0	18.1	18.1
Total-NERC	**740,911**	**987,168**	**52,994**	**24.9**	**28.8**

Notes to Tables 1a, 1b, 1c and 1d

Net Internal Demand — 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. Demand served under liquidated damages contracts is included.

Net Capacity Resources — Existing available generating capacity committed to serving demand, plus new units scheduled for service by the given month, plus the net of firm capacity purchases and sales, does not reflect potential fuel supply problems or hydro limitations.

Uncommitted Resources — Generating resources that are built or expected to be in operation, but are not counted toward capacity margin and reserve margin calculations.

Uncommitted resources may include one or more of the following:

- Generating resources that have not been contracted nor have legal or regulatory obligation to deliver at time of peak
- Generating resources that do not have or do not plan to have firm transmission service reserved (or its equivalent) or capacity injection rights to deliver the expected output to load within the region
- Generating resources that have not had a transmission study conducted to determine the level of deliverability
- Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources
- Transmission-constrained generating resources that have known physical deliverability limitations to load within the region

Available Capacity Margin[10] — The difference between net capacity resources (available committed resources) and net internal demand, expressed as a percentage of net capacity resources. Variations from capacity margins in regional tables may exist due to differences in reporting methods for purchases and sales.

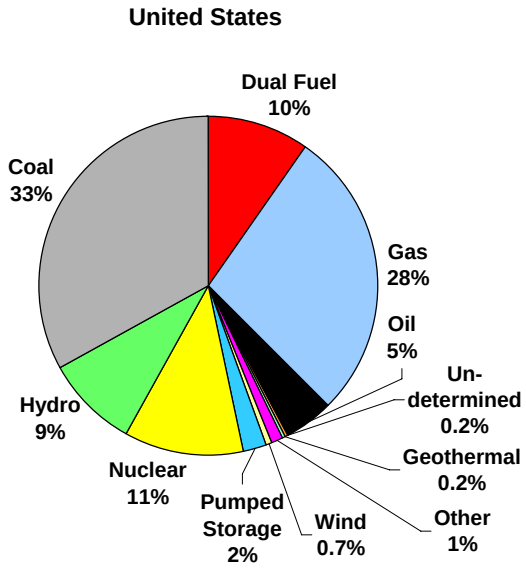
Potential Capacity Margin[11] — The difference between total potential resources and net internal demand, expressed as a percentage of total potential resources. This is the capacity that could be available to cover random factors such as forced outages of generating equipment, demand forecast errors, 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.

[10] This differs from Reserve Margin which is expressed as difference between total potential resources and net internal demand, expressed as a percentage of net internal demand. Capacity margin is used in NERC's assessment to enable comparative analysis with other industries which evaluate capacity factors as a percentage of capacity rather than production.

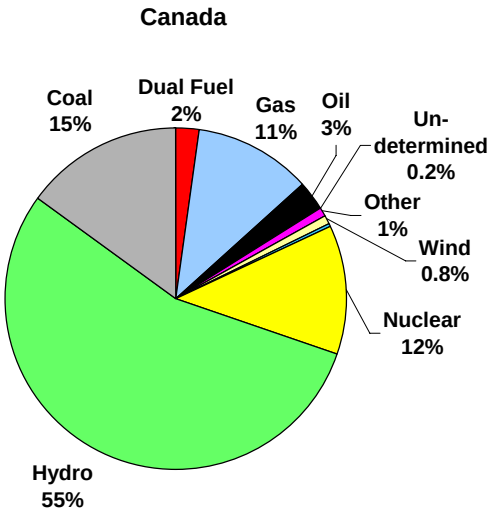
[11] Potential capacity margins assume the capacity from uncommitted generation is deliverable.

WECC CA-MEX — Represents only the northern portion of the Baja California Norte, Mexico, electric system that is interconnected with the United States.

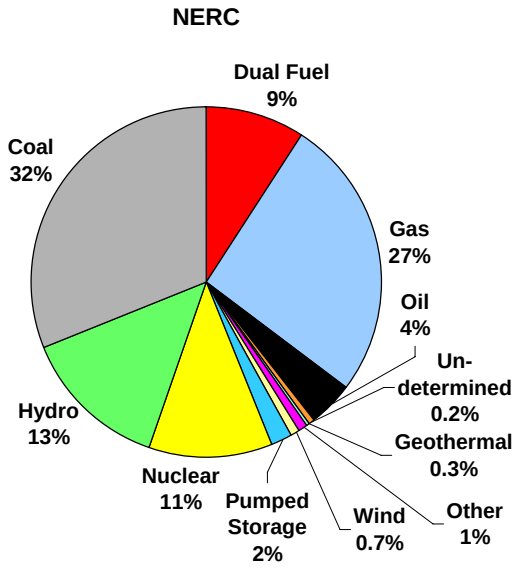
Projected Capacity Fuel Mix — Summer 2007



U.S. Capacity Fuel Mix

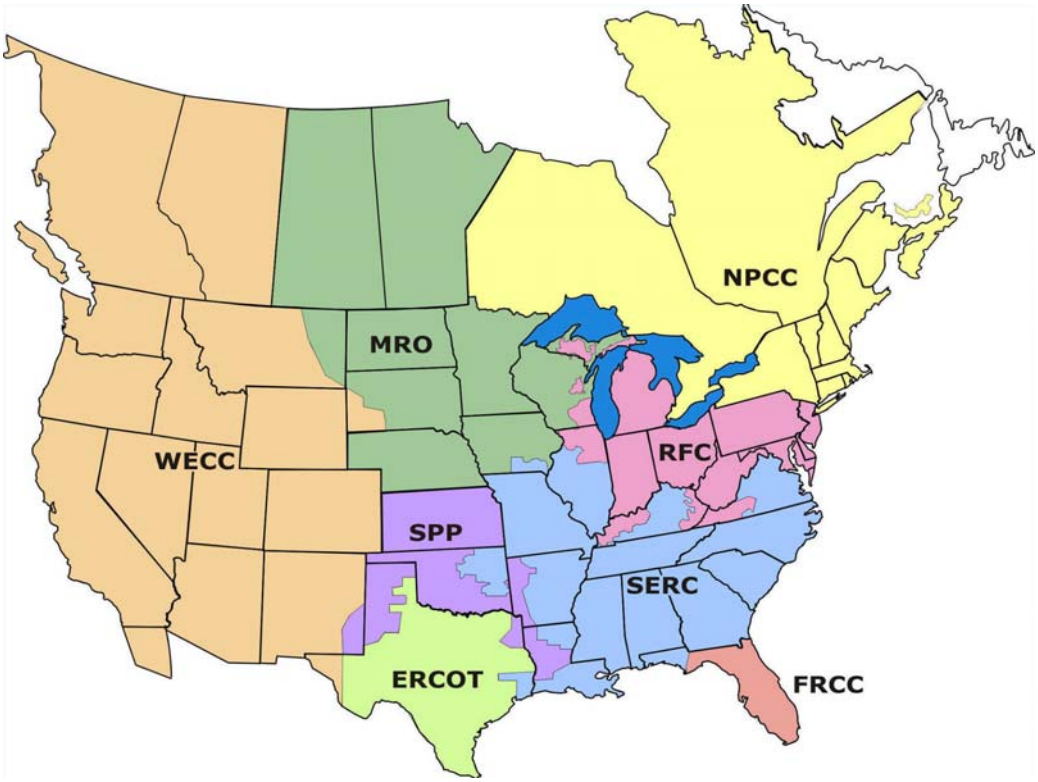


Canadian Capacity Fuel Mix



NERC-wide Capacity Fuel Mix

NERC Regional Reliability Organizations



ERCOT
Electric Reliability Council of Texas, Inc.

FRCC
Florida Reliability Coordinating Council

MRO
Midwest Reliability Organization

NPCC
Northeast Power Coordinating Council

RFC
Reliability*First* Corporation

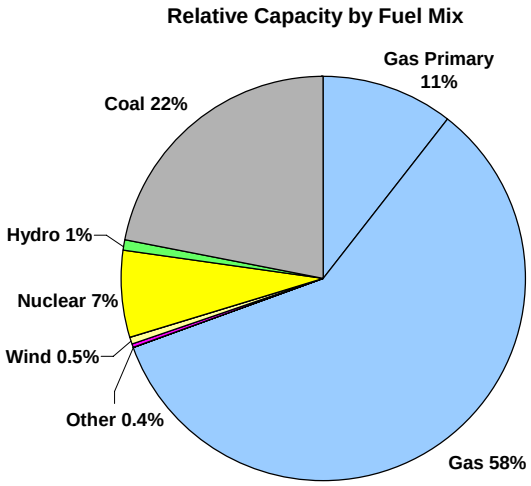
SERC
SERC Reliability Corporation

SPP
Southwest Power Pool, Inc.

WECC
Western Electricity Coordinating Council

Regional Self-Assessments
ERCOT

Projected Total Internal Demand	63,794	MW
Interruptible Demand & DCLM	1,112	MW
Projected Net Internal Demand	62,682	MW
Last Summer's Peak Demand	62,339	MW
Change	2.3	%
All-Time Summer's Peak Demand	62,339	MW
Deliverable Internal Capacity	71,346	MW
Projected Purchases and Incoming Adjustments	116	MW
Projected Sales and Outgoing Adjustments	218	MW
Net Capacity Resources	71,244	MW
Capacity Margin	12.0	%
Reserve Margin	13.7	%
With Uncommitted Resources		
Total Potential Resources	71,244	MW
Capacity Margin	12.0	%
Reserve Margin	13.7	%



Demand

The 2007 summer peak demand forecast of 63,794 MW is based on an econometric model that uses the historical trend adjusted for economic and weather variables, primarily temperatures, heating and cooling degree-days. It is an increase of 2.3% from the 2006 actual peak demand of 62,339 MW which was also ERCOT's all-time peak demand. The ERCOT system forecast for 2007 is 3.5% higher than last year's forecast mainly due to a more optimistic economic outlook for the state of Texas, including ERCOT's territory. The key factors driving the higher peak demands and energy consumption forecasts are reflective of the overall health of the economy as captured by economic indicators such as the real per capita personal income, population, and various employment measures including non-farm employment and total employment. These economic variables are used throughout the eight weather zones that comprise the ERCOT electric grid. This increase is also the result of some model adjustments to individual weather zones to correct for forecast error from last year.

Last year there were two separate efforts to quantify peak demand uncertainty and variability due to extreme weather and/or other conditions. The first approach uses Monte Carlo simulation by simulating a number of forecasts by perturbation of the forecast parameters. The second method produces forecasts using temperatures at the 90th percentile of all temperatures in the last twelve years. This year, the 90% confidence bands were developed using the second approach. The forecast for 2007 is 63,794 MW and the preliminary 90% band is 67,209 MW or 5.35% higher than the forecast based on normal weather.

Transfers of 218 MW to the SPP are due to SPP members' ownership of that amount of capacity of a power plant located in ERCOT.

Interruptible loads make the 1,112 MW available through ERCOT's ancillary services market. The ERCOT retail market may contain additional amounts of load management that is not quantified. The difference in the 1,150 MW reported last year and the 1,112 MW reported this year is due to a difference in calculation methodology. For 2006, the entire amount of interruptible load that is registered with ERCOT was included. For 2007 the amount was derived through a statistical approach based on having a 95% confidence in the end result. The mean and standard deviation were calculated from the total number of hourly observations resulting in the 1,112 MW reported.

Resource Assessment

The projected capacity margin at peak according to the NERC requested calculation method for this assessment is 12% and is above the corresponding regional minimum requirement of 11% (12.5% reserve margin). The actual capacity margin during the peak hour for 2006 was 12.1% according to the NERC calculation method. The slight decrease in capacity margin forecast for 2007 is due to the higher demand forecast. Some new generation capacity was added during the year and some capacity is being taken out of mothball status. Below is a table showing the non-wind resources added, including mothballed units returned to service, since the summer of 2006.

Non-Wind Resources Added Since Summer 2006

Unit Name	In-Service Date	Capacity, MW	Notes
Colorado Bend Energy Center 1	4/2/2007	105	New generation
Colorado Bend Energy Center 2	4/2/2007	76	New generation
Colorado Bend Energy Center 3	4/2/2007	76	New generation
Unnamed DG Plant	11/1/2006	4.8	New generation
Quail Run Energy Center 1	4/1/2007	98.1	New generation
Quail Run Energy Center 2	4/1/2007	83	New generation
Quail Run Energy Center 3	4/30/2007	83	New generation
North Lake 1	6/1/2007	156	Returned from mothball
North Lake 2	6/1/2007	181	Returned from mothball
North Lake 3	6/1/2007	389	Returned from mothball
	Total	**1251.9**	

There is a total of 820 MW of DC tie transfer capability between ERCOT and SPP and 136 MW of capability between ERCOT and Mexico Comision Federal Electricidad, of which only 116 MW are shown in the assessment. Entities in SPP can call on 218 MW of capacity in ERCOT and it is classified as a capacity sale from ERCOT.

Approximately 1,215 MW of new generation capacity, including 689 MW of nameplate wind generation, is expected to commence commercial operation before the summer peak in 2007. Only 8.7% of the wind generation nameplate capacity (about 60 MW) is used towards committed resources in the ERCOT region.

The "net dependable" committed capacity of wind generation was determined differently from the previous years. The recent ERCOT loss of load probability (LOLP) study, which includes a determination of the Effective Load Carrying Capability of wind (ELCC), also takes into account the volatility of wind using generation patterns from a recently completed ERCOT study entitled, *Transmission Alternative for Competitive Renewable Energy Zones in Texas*

(www.ercot.com/news/presentations/index/html). A copy of ERCOT's loss of load probability (LOLP) and Effective Load Carrying Capability (ELCC) study is footnoted[12].

ERCOT is a separate electric interconnection with a single planning authority, balancing authority, and reliability coordinator. The ERCOT planning authority verifies that there will be a feasible dispatch of all available generation in ERCOT to meet energy and operating reserve requirements without violating transmission system limits under numerous contingencies according to NERC Standards. Operationally, transmission operating limits are adhered to through market-based generation re-dispatch directed by ERCOT as the balancing authority and reliability coordinator. Operational resource adequacy is also maintained by ERCOT through market-based procurement processes. (See Sections 6 and 7 of the ERCOT Protocols[13]).

Although projected available resources this summer will meet ERCOT's adequacy criteria, they are expected to be close to the minimum required by the criteria. An extremely hot summer that results in load levels significantly above forecast, higher than normal unit forced outage rates, or financial difficulties of some generation owners that may make it difficult for them to obtain fuel from suppliers are all risk factors that alone or in combination could result in inadequate supply. In the event that occurs, ERCOT will implement its Emergency Electric Curtailment Plan (EECP) (See Section 5.6.6.1 of the ERCOT Protocols[14]). The EECP includes procedures for use of interruptible load, voltage reductions, procuring emergency energy over the DC ties and load shedding to avoid system collapse.

Fuel

No comprehensive fuel supply interruption analysis was considered necessary for the summer. Natural gas fuel supply interruptions, a potential concern during the winter in ERCOT due to the demand for gas for home heating, typically do not occur during the summer. No significant disruptions in gas supply were experienced in ERCOT last summer. No significant problems with coal supply deliveries in ERCOT are expected this summer.

Transmission Assessment

No unusual transmission flow patterns are expected for the summer. ERCOT currently has five Commercially Significant Constraints (CSC) where transmission flows typically encounter congestion:

- South Texas to North Texas
- West Texas to North Texas
- North Texas to West Texas
- North Texas to Houston
- South Texas to Houston

The Laredo area has experienced large load growth over the years. The existing transmission system cannot support the energy imports necessary to satisfy the area and maintain N-1 security requirements. Currently, ERCOT has three units under Reliability Must-Run (RMR) contract in Laredo for a total capacity of 169 MW. Transmission line upgrades that will allow releasing the

[12] http://www.ercot.com/meetings/gatf/keydocs/2007/20070112-GATF/ERCOT_Reserve_Margin_Analysis_Report.pdf.
[13] http://www.ercot.com/mktrules/protocols/current.html
[14] http://www.ercot.com/mktrules/protocols/current.html

RMR contract are planned to be completed in 2010. In the interim, a 100-MW Variable Frequency Transformer tie with Mexico is being installed. This device will not allow releasing the RMR units but will help ensure that adequate capacity is available to restrict the Laredo energy imports to acceptable levels that satisfy the Laredo area security criteria.

The 345-kV Elm Creek switching station is currently being built to the east of San Antonio and will help reduce congestion in the San Antonio area. In addition, the 345-kV Hillje and Oasis switching stations are going in service this spring in the Houston area. These stations will help increase energy imports into Houston via the South to Houston CSC.

ERCOT has interconnections through DC ties with the Eastern Interconnect and with Mexico. The maximum imports/exports over theses ties are 1,106 MW. These ties can be operated at maximum import and export provided there are no area transmission elements out of service. In the event of a transmission outage in the area of these ties, studies will be run during the outage coordination period for transmission outages to see if any import/export limits are needed during the outages. Otherwise, no special studies are done to determine capacity assistance from resources outside of ERCOT.

The loss of the Tradinghouse – Venus 345 kV double circuit line as a result of severe wind storm in Texas is not expected to create any reliability problems this summer. While ERCOT will be able to maintain its security criteria, the absence of the line has required ERCOT intervention to offset generation schedules provided by the market. Flows normally carried by these circuits are now flowing on underlying 69 and 138 kV lines, which have lower line ratings. Generally, this can be handled by generation re-dispatch. The double circuit is scheduled to return on May 21, 2007, well before the highest peak months of July and August.

Operational Issues

All planned outages on transmission elements that significantly reduce intra-ERCOT transfers are typically scheduled to be completed by May 15th. No unusual operating conditions that would impact system reliability are expected this summer.

The number or use of remedial actions, special protection systems, or use of operational reserves has not changed significantly from summer 2006. Provisions for voltage reductions, procurement of emergency energy over the DC ties and load shedding in case of capacity insufficiency are prescribed in the ERCOT EECP. The ERCOT EECP Procedures were recently revised due to implementation of the EECP on April 17, 2006. On this day, unseasonably high temperatures in the Austin-San Antonio and DFW Areas raised ERCOT loads to those typically seen in the summer time. With several units off line for planned outages, resources were stretched as temperatures hit 100 degrees throughout North Texas.

Currently, ERCOT is discussing the possibility of adding a new ancillary service called Emergency Interruptible Load Service (EILS). EILS is designed to be used at the end of an EECP event. The objective is to shed voluntary firm load prior to shedding involuntary load. In return the voluntary firm load customers would be compensated by a small payment. EILS load are deployed after the Loads acting as Resources (LaaRs) but before the involuntary firm load. EILS loads are still considered firm load and should not be considered as an offset to net demand.

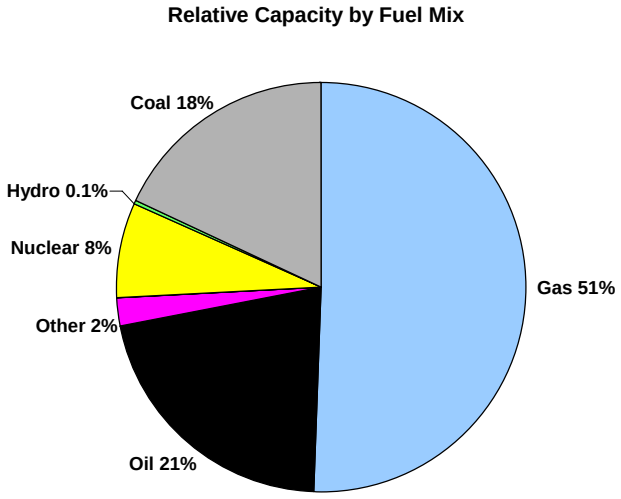
There are no environmental and/or regulatory restrictions known at this time that could potentially impact reliability. If something occurs, it will be addressed in a way to ensure reliability standards are met and maintained.

The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to approximately 20 million Texas customers – representing 85 % of the state's electric load and 75 % of the Texas land area. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects 38,000 miles of transmission lines and more than 500 generation units. ERCOT also manages financial settlement for the competitive wholesale bulk-power market and administers customer switching for 5.9 million Texans in competitive choice areas.

ERCOT is a membership-based 501(c)(6) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT's members include retail consumers, investor- and municipal-owned electric utilities, rural electric cooperatives, river authorities, independent generators, power marketers and retail electric providers. (www.ercot.com)

FRCC

Projected Total Internal Demand	46,878	MW
Interruptible Demand & DCLM	3,054	MW
Projected Net Internal Demand	43,824	MW
Last Summer's Peak Demand	45,751	MW
Change	2.5	%
All-Time Summer's Peak Demand	46,396	MW
Deliverable Internal Capacity	49,627	MW
Projected Purchases and Incoming Adjustments	2,398	MW
Projected Sales and Outgoing Adjustments	0	MW
Net Capacity Resources	52,025	MW
Capacity Margin	15.8	%
Reserve Margin	18.7	%
With Uncommitted Resources		
Total Potential Resources	53,171	MW
Capacity Margin	17.6	%
Reserve Margin	21.3	%



Demand

The Florida Reliability Coordinating Council (FRCC) is forecast to reach its 2007 summer peak demand of 46,878 MW in August, which represents a projected demand increase of 2.5 % over the actual 2006 summer demand of 45,751 MW. This projection is consistent with historical weather-normalized FRCC demand growth and is 3.0% higher than last year's summer forecast of 45,520 MW. This increase in the 2006 summer peak demand is attributed to normal temperatures and typical growth. The 2007 net internal demand forecast includes the affects of 3,054 MW of potential demand reductions from the use of load management and interruptible load management programs composed of residential, commercial and industrial demand.

FRCC employs two different techniques to assess the peak demand uncertainty and variability. First, FRCC develops regional bandwidths on the projected or most likely load (90/10). This forecast on peak demand can be interpreted to mean that there is a 10% probability that in any year of the forecast horizon that actual observed demand could exceed the high band. The purpose of developing bandwidths on peak demand is to quantify uncertainties of demand at the regional level. This would include weather and non-weather load variability such as demographics, economics and price of fuel and electricity.

In addition, Monte Carlo Simulations on peak demands are performed to arrive at a probabilistic distribution as to range and likelihood of this range of outcomes of peak demand. Factors that determine the level of demand for electricity are assessed in terms of their own variability and this variability incorporated in the simulations.

Once the determination of possible peak demand values or variability is completed as outlined above on the statewide aggregated peak demands, these possible outcomes are compared to installed and planned generation to determine the degree of reliability of the electrical system of

the FRCC region. If the installed and planned generation is sufficient to cover a significant portion of the load variability, then the system is deemed to be reliable on a forecast basis.

Resource Assessment

The net capacity resources available within the region to meet the projected summer peak yields a 21.4% reserve margin, exclusive of uncommitted resources, adequately satisfying the 15% regional reserve margin requirement. This margin is higher than last year's forecast of 19.8% reserve margin, and includes 1,552 MW of deliverable external long-term firm non-recallable purchases from outside the region. An additional 1,873 MW of firm net generation is scheduled to be online prior to the upcoming summer season, mostly attributable to the addition of new natural gas generation. No uncommitted generation has been reported for commercial operation for the upcoming summer season.

Only existing capacity that is under firm contract or committed to serve load has been included in FRCC's capacity resources. FRCC has 5,062 MW of existing merchant plant capacity, of which 3,916 MW are under firm contract and have been included in committed capacity resources. The committed resources are included in the various system operating conditions that are studied.

In the event of actual peak demands higher than expected due to weather or other conditions, the FRCC Region has an adequate resource reserve margin to meet a 5% higher than expected demand and still maintain the 15% reserve margin requirement. These additional resources can be adequately delivered throughout the FRCC Region. Therefore, regional resource adequacy is achieved throughout the FRCC Region by having sufficient resources available and the capability to deliver these resources.

Fuel

Operators within the FRCC typically use the fuel supply infrastructure in accordance with design capabilities as most fuel delivery infrastructure is designed around projected loading, and in accordance with market economic drivers. The type of infrastructure used and preferred generation dispatch is based on economic conditions surrounding the types of fuels, along with availability of external purchased power. Typically, during peak summer conditions, some alternate fuel-type unit dispatch may be used depending on system economics.

The FRCC Regional Load and Resource Plan is developed on an annual basis and includes specification of primary and secondary fuel sources for generating facilities. Based on the interdependence of generating capacity on natural gas, the FRCC continues initiatives to increase coordination among natural gas suppliers and generators within the region. This coordination continues to provide the data necessary to perform short-term natural gas availability assessments in order to provide operators with near-term assessments of the gas delivery system on a regionally coordinated basis for appropriate operational recommendations. The FRCC continues to assess and coordinate responses to regional fuel supply impacts and issues, including fuel inventory and alternate supply availability, as they are identified.

In addition to the short-term fuel assessment coordination processes, the FRCC continues work on a more detailed natural gas pipeline and electric interdependency study process. The FRCC

has developed a high-level, transient gas flow model to study and analyze the gas pipeline system and its impact on reliability in peninsular Florida. Additional data related to natural gas usage within the region has been collected, modeled and used to evaluate reliability impacts of gas supply constraints and the mitigation capabilities within the Region.

For the 2007 summer period, fuel supplies continue to be adequate for the Region. There are no identified fuel availability or supply issues at this time, and no additional mitigation strategies have been developed. Based on current fuel diversity and alternate fuel capability, the FRCC does not anticipate any fuel transportation issues affecting capability during peak periods.

Transmission Assessment

FRCC expects the bulk transmission system to perform adequately over various system operating conditions. The results of the 2007 Summer Transmission Study, which evaluated the steady-state summer peak load conditions under different operating scenarios, indicate that any thermal or voltage concerns can be managed successfully by operator intervention. Such operator interventions can include generation re-dispatch, system reconfiguration, reactive device control, and transformer tap adjustments.

Major additions or changes to the FRCC transmission system are mostly related to expansion in order to serve new demand and therefore, none of these additions or changes would have a significant impact on the reliability of the transmission system. For the summer of 2007, no additional transmission constraints have been identified primarily because typical transmission system flow patterns have not changed significantly since the summer of 2006.

Transmission constraints in the Central Florida area may require remedial actions depending on system conditions creating increased west-to-east flow levels across the Central Florida metropolitan load areas. Permanent solutions have been identified and implementation of these solutions is underway. Transmission configuration changes have been implemented to mitigate some of these concerns. This summer, remedial operating strategies have been developed and will continue to be evaluated to ensure system reliability.

An interregional transfer study is performed annually to evaluate the transfer capability between FRCC and the southern subregion of SERC for the upcoming summer and winter seasons. Joint studies of the Florida/Southern transmission interface indicate an import capability of 3,600 MW into FRCC, and export capability of 1,500 MW. Any transfer-related contingencies resulting in transmission overloads or voltage violations can be resolved by operational strategies.

Operational Issues

No scheduled generating unit or transmission facility maintenance outages of any significance are planned for the summer period. In addition, there are no environmental and/or regulatory restrictions that potentially impact reliability in the FRCC Region for the 2007 summer period.

If the FRCC Region experiences higher than expected load levels, the same sensitivities to area dispatches and transmission configuration are expected as operational issues for the summer 2007. Unplanned outages of generating units may aggravate the existing transmission constraints. However, it is also anticipated that, should any operational issues arise; pre-

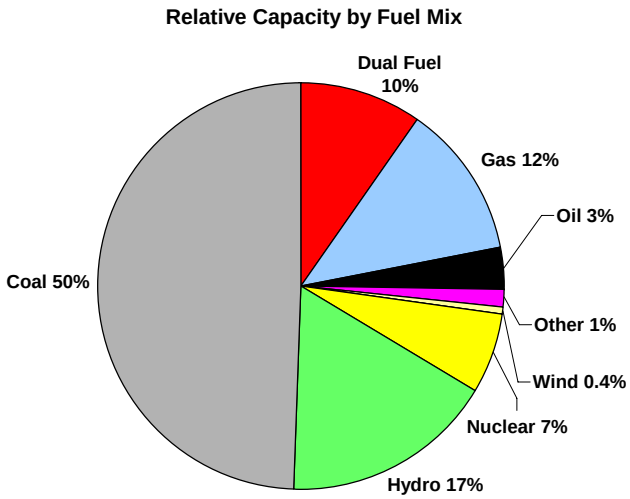
planning, training and operational strategies will adequately manage and mitigate the impacts to the bulk system in the area.

FRCC's membership includes 28 members, which is composed of investor-owned utilities, cooperative systems, municipal utilities, power marketers, and independent power producers. Historically, the region has been divided into 11 balancing authorities.

As part of the transition to the ERO, FRCC has registered 80 entities (both members and nonmembers) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards glossary. The region contains a population of more than 16 million people, and has a geographic coverage of about 50,000 square miles over peninsular Florida. Additional details are available on the FRCC Web site (http://www.frcc.com).

MRO

Projected Total Internal Demand	49,102	MW
Interruptible Demand & DCLM	1,925	MW
Projected Net Internal Demand	47,177	MW
Last Summer's Peak Demand	46,059	MW
Change	6.6	%
All-Time Summer's Peak Demand	46,059	MW
Deliverable Internal Capacity	52,784	MW
Projected Purchases and Incoming Adjustments	4,748	MW
Projected Sales and Outgoing Adjustments	525	MW
Net Capacity Resources	57,007	MW
Capacity Margin	17.2	%
Reserve Margin	20.8	%
With Uncommitted Resources		
Total Potential Resources	57,107	MW
Capacity Margin	17.4	%
Reserve Margin	21.0	%



The Midwest Reliability Organization replaced the Mid-Continent Area Power Pool (MAPP) as a regional reliability organization within North American Electric Reliability Corporation in January 2005. MAPP continues to exist as a regional transmission group with a Regional Transmission Committee and a Generation Reserve Sharing Pool. The MRO membership expanded its geography in 2005 with a new Canadian member, SaskPower. In January 2006, the MRO acquired additional members from the former Mid-America Interconnected Network, Inc. (MAIN) regional reliability council.[15]

Demand

The Midwest Reliability Organization's (MRO) expected 2007 Summer Non-Coincident Peak Net Internal Demand in the combined MRO US and MRO Canada is 47,177 MW, assuming normal weather conditions. This forecast is 4.2% above last summer's peak demand forecast of 45,286 MW and 2.4% above last summer's actual peak demand of 46,059 MW. Above average temperatures throughout the MRO region were primarily responsible for last summer's peak demand exceeding the forecast, which assumed normal weather patterns.

Each MRO member's peak demand forecast includes factors involving recent economic trends (industrial, commercial, agricultural, residential) and normal weather patterns. From a regional perspective, there were no significant changes in this year's forecast assumptions in comparison to last year.

Interruptible Demand and Demand Side Management (DSM) programs, amounting to approximately 4% of the MRO's Projected Net Internal Peak Demand, are utilized by a number

[15] The former MAIN members are Alliant Energy , Wisconsin Public Service Corp., Upper Peninsula Power Co., Wisconsin Public Power Inc., and Madison Gas and Electric

of MRO members. A wide variety of programs, including direct load control (such as electric appliance cycling) and interruptible load are used to reduce peak demand during the summer season. Within the MRO, there is a projected 1.6% increase in Interruptible Demand & DSM for the 2007 summer season when compared to last summer's forecast.

Peak demand uncertainty and variability due to extreme weather and/or other conditions are accounted for in the determination of adequate generation reserve margin levels. Both the MAPP Generation Reserve Sharing Pool (GRSP) members and the former MAIN members within MRO[16] utilize a Load Forecast Uncertainty (LFU) factor in the calculation of Loss of Load Expectation (LOLE) and/or the percentage reserve margin necessary to obtain a LOLE of 0.1 day per year or 1 day in 10 years. The load forecast uncertainty considers uncertainties attributable to weather and economic conditions.

High and low demand forecasts for the SaskPower system were simulated using a Monte Carlo method to reflect economic and weather uncertainties. This model considers each uncertainty independently from other variables and assumes a probability distribution around the expected demand forecast. Results are based on a 90/10 forecast.

Resource Assessment

The MRO's projected 2007 Summer MRO Reserve Margin is 20.8% without uncommitted resources. This is a 0.6% increase when compared to the projected 2006 Reserve Margin of 20.2%. This is directly attributable to the 803 MW of Planned Additions of New Capacity within the MRO for the 2007 summer season.

For the MAPP GRSP, which includes all MRO members except the former MAIN members and SaskPower, resource adequacy is measured through accreditation rules and procedures. The MAPP GRSP requires a 15% reserve capacity obligation to be verified after the fact. The MRO is projecting that the MAPP GRSP members have 20.7% reserve margin for the 2007 summer season, which is in excess of the minimum required Reserve Margin.

The former MAIN members now within MRO do not belong to the MAPP GRSP. Generation resource adequacy for the former MAIN members is assessed based on LOLE studies previously conducted by the MAIN region. Although conducted on a yearly basis, MAIN's LOLE studies consistently recommended a minimum short-term planning reserve margin of 14%. For the upcoming 2007 summer season, the Reserve Margin of the former MAIN members is 19.1%, which is in excess of the minimum recommended Reserve Margin.

SaskPower's reliability criterion is based on annual expected unserved energy analysis and equates to an approximate 15% reserve margin requirement. SaskPower's projected reserve margin for upcoming 2007 summer season is 29.8%.

Uncommitted capacity within the MRO region consists of 100 MW of Energy-Only Resources for the upcoming 2007 summer season. This uncommitted capacity is approximately 0.2% of the Deliverable Internal Capacity within the MRO.

[16] The former MAIN members are Alliant Energy , Wisconsin Public Service Corp., Upper Peninsula Power Co., Wisconsin Public Power Inc., and Madison Gas and Electric

For the 2007 summer season, the MRO is projecting an import of 4,748 MW. This capacity includes imports into the MRO region from other surrounding regions and purchases from Independent Power Producers (IPPs) within the MRO region. The MRO will be exporting approximately 525 MW of Projected Sales out of the MRO region.

Throughout the MRO region, firm transmission service is required for all generation resources that are utilized to provide firm capacity; also meaning that these firm generation resources are fully deliverable to the load. The MRO is forecast to meet the various reserve margin targets without needing to include energy-only, uncommitted, or transmission-limited resources.

While reservoir water levels continue to remain low throughout the northern portion of the MRO U.S. region (Montana, North Dakota, and South Dakota), they are sufficient to meet projected peak demand and energy requirements for the 2007 summer season, as indicated in the various regional reserve margin calculations. The Saskatchewan and Manitoba water levels are projected to be at normal levels for the upcoming 2007 summer season.

Fuel

Unless the MRO members identify a known or anticipated fuel supply or delivery issue, this topic is not considered in the MRO's resource adequacy assessment due to the diversity in fuel supply and/or attainment methods throughout the region. However, the MRO and its members continue to closely monitor the delivery of Powder River Basin coal to ensure adequate supply. The MRO does not foresee any other significant fuel supply and/or fuel delivery issues for the upcoming 2007 summer season. Therefore, there should be no apparent impacts to the reliability of meeting peak demand for the 2007 summer season.

Transmission Assessment

The MRO transmission system is judged to be adequate to meet the firm obligations of the member systems for this coming season. The reliability of the transmission system is currently measured by determining thermal, voltage, and dynamic stability limitations and by studying the historical performance of the transmission system. Several steady-state studies, which provide an indication of transmission system strength and the necessary data to facilitate analyses of the MRO network, are conducted annually.

Inter-Regional Assessment

The following discussion is based on the ongoing MRO/RFC/SPP/SERC-W 2007 Summer Inter-regional Assessment (Reference 1). In this 2007 study model, there was a decrease in the level of base case transfers into the MRO Region when compared to 2006 import levels attributed to the MISO-PJM market dispatch assumed in the study model, and this has resulted in the increase of the First Contingency Incremental Transfer Capability (FCITC) values as compared to the 2006 Summer Transmission Assessment Study.

Preliminary results from the aforementioned study indicate the First FCITC Non-simultaneous Import Capabilities into MRO from the RFC, SERC and SPP regions are: RFC to W-MRO (250 MW), SPP to MRO (2,300 MW) and SERCW to MRO (350 MW).

MRO Import Capabilities

The MRO import FCITC from Western RFC is 250 MW, an increase from 0 MW for the 2006 summer. The increased imports can be attributed to the MISO-PJM market dispatch assumed in the study model and the installation of the Werner West 345/138 kV transformer.

The MRO import FCITC from SPP is 2,300 MW, a significant increase from 0 MW for the 2006 summer. This increase can also be attributed to the change for the MISO-PJM market dispatch in the 2007 summer model.

The MRO import FCITC from Western SERC is 350 MW, an increase from 0 MW for the 2006 summer. This increase can be attributed to the transmission system changes that result in a different limiting element.

Sub-regions

Assessments for the individual sub-regions are provided below.

Iowa

A pre-dominant flow pattern that was observed in Iowa during the last several years, characterized by heavy East to West power transfers across Iowa, is expected to be less influential during the summer of 2007. The primary reason for this change is the addition of the Council Bluffs Energy Center Unit-4, which is expected to be fully operational during this summer season. However, the South to North system bias, which was also observed during last summer, is expected to continue to cause TLR calls and implementation of the MISO congestion management procedures. In accordance with the recommendations from the NERC Alliant Task Force Report, Alliant Energy's transmission system in eastern Iowa will be monitored by MISO and ATCLLC, while transmission providers are expected to continue with their coordination procedures in the interest of increasing reliability of the transmission system in eastern Iowa.

The Council Bluffs Energy Center Unit-4 (CBEC-4), with a net generating capacity of 790 MW, is a new coal-fueled generating plant located at the existing Council Bluffs Energy Center. Steady state and dynamic studies have shown that the addition of the Council Bluffs Energy Center Unit-4 will not cause any significant single contingency based reliability concerns. Operating guides will be prepared to address local area problems that may be caused by double contingencies. Transfer analysis indicated that facilities north of Council Bluffs will become less limiting for north to south power transfers, while facilities south of Council Bluffs will become more limiting for north to south power transfers. Significant transmission projects were completed prior to synchronization of the CBEC-4 unit to address reliability impacts of the CBEC-4 on affected constrained interfaces. It is expected that the MidAmerican Energy Greater Des Moines Energy Center and Alliant Energy Emery Plant will continue to significantly contribute to more reliable system conditions in Central Iowa and North-East Iowa. The new Emery–Lime Creek 161 kV line is expected to be completed prior to Summer 2007.

Four new OTDF flowgates that were added to the MAPP and MISO request evaluation process in 2006 and early 2007 will provide effective protection against overselling the transmission system, pre-dominantly in the East to West direction. Two 161 kV transmission lines in Central Iowa that used to cause TLR calls during previous summers were re-conductored in 2006. The

standing operating guides for these and all other flowgates are available to system operators and Reliability Coordinators. Operating Guides have proven to be effective in dealing with operational issues associated with Iowa flowgates. Requests for scheduled transmission outages will be carefully processed and analyzed according to regional policies and procedures and temporary operating guides will be prepared if results of analysis show potential operational problems caused by either scheduled or forced transmission or generation outages.

Overall, the Iowa system is expected to operate in a reliable manner during the summer of 2007 by meeting NERC Reliability standards and the MRO regional reliability criteria.

Nebraska

Nebraska Public Power District (NPPD) and Omaha Public Power District (OPPD) currently post six constrained paths on the MAPP and MISO OASIS which are located within or adjacent to the NPPD and OPPD control areas. All of these interfaces have approved operating guides that have historically proven to be effective in dealing with system conditions throughout the year.

During December 21-31, 2006, two severe ice storms caused extensive damage to the NPPD high voltage transmission system. At the height of the second storm, 37 high voltage transmission lines were out of service in the NPPD system. These ice storms affected over 830 miles of NPPD's high voltage transmission lines resulting in complete structure failure on over 270 miles. All storm-damaged transmission lines have been returned to service, and the system is expected to operate normally during the remainder of the summer 2007 season.

During the summer peak and off-peak loading periods, two export interfaces are monitored closely including the Cooper South Interface (COOPER_S) and the Western Nebraska to Western Kansas Interface (WNE_WKS). Upgrades are expected to be completed prior to the 2007 summer season which should result in less frequent TLR events. During peak loading periods with heavy exports to the south, NERC TLR is expected to be implemented to address operating security limits associated with the north to south flowgates.

With increased loads in the western Nebraska region during the summer months, stability limitations associated with the Gerald Gentleman Station Stability (GGS) Interface are less severe. High power transfers out of the western Nebraska region are typically less during the summer months than in winter months. Prior outage limitations will be enforced on the GGS Stability Interface until all storm damaged bulk transmission facilities are returned to service.

In the past several years, there has been a large increase in the number of days the DC ties are transferring power from east-to-west which reduces the west-to-east flows that are normally seen across Nebraska. It is anticipated that this pattern of the DC ties flowing in the east-to-west direction will continue this summer.

Northern MRO

The Northern MRO region consists of the Dakotas, Minnesota, part of Montana, and the Canadian provinces of Manitoba and Saskatchewan. No significant operational issues are expected this summer for the Northern MRO region. The existing operating guides, and

temporary operating guides that are developed as needed, have maintained reliable system conditions throughout the year. Reservoir water levels continue to remain low throughout the northern MRO US region (Montana, North Dakota, and South Dakota), and will likely continue to reduce the magnitude and duration of exports out of northern MRO, and also continue to contribute to the recent significant imports of power into the MRO region. The Manitoba water levels are normal. Therefore, normal Manitoba-US exports are likely. Saskatchewan reservoirs are at normal conditions, and normal Saskatchewan-Manitoba-US transfers are likely.

The Stone Lake-Gardner Park (Weston) 345 kV line was completed in December 2006 and will be in-service this summer. The 345-161 kV transformer at Stone Lake is beneficial in supporting the northwestern Wisconsin area during the outage of Stone Lake-Stinson 161 kV for the construction of a double circuit 161/345 kV line (Arrowhead-Stone Lake 345 kV). This line is expected to be completed by March 2008, and will have a significant impact on the northern MRO system. Studies are underway to redefine and develop transfer limits for the Minnesota-Wisconsin interface.

The second Lakefield-Fox Lake 161 kV circuit was installed this past fall and was the final transmission upgrade requirement to obtain 425 MW of firm capacity from the wind generation in southwestern Minnesota (Buffalo Ridge area).

The addition of wind generation in northern Iowa and southern Minnesota coupled with the Emery combined cycle gas generation addition near Mason City, Iowa, has caused increased loading in southeastern Minnesota. Operating guide(s) will be implemented for the affected facilities.

Dairyland Power and XCEL Energy plan to complete the re-conductor of the Genoa-Coulee 161kV line by May, 2007. This upgrade will remove a chronic limiting facility that has historically resulted in numerous TLR events.

Due to recent reinforcements, the Adams – Rochester 161 kV line is a potential next new constraint for the 2007 summer season. This circuit will be closely monitored and added to the appropriate transmission service processes and congestion management processes as required.

Overall, the northern MRO system should be able to operate under all load and firm exchange levels while meeting the regional reliability criteria.

Wisconsin-Upper Michigan

The WUMS electric transmission system encompasses the service territories of five (5) Balancing Authorities - Alliant Energy-Wisconsin Power & Light, We Energies, Wisconsin Public Service Corporation, Madison Gas & Electric Company and Upper Peninsula Power Company. The WUMS system consists of 345, 230, 161, 138, 115 and 69 kV transmission facilities and is owned by American Transmission Company, LLC (ATCLLC). The operation of WUMS is coordinated between ATCLLC and the Midwest Independent System Operator (Midwest ISO).

Reliable operation of the WUMS transmission system is expected during the summer 2007 season. (References 2, 3, 4, 5)

A number of transmission additions and upgrades are completed or expected to be completed before summer 2007 since last summer. These additions and upgrades strengthen the reliability of the WUMS system for the summer of 2007 and years to come. Listed below are the major transmission projects with in-service (or expected in-service) dates before summer 2007.

- Construction of a Gardner Park-Stone Lake 345 kV line. Went in service in December 2006.
- Installation of a Werner West 345/138 kV substation with a 500 MVA 345/138 kV transformer. Went in service in December 2006.
- A number of other re-conductoring projects and conversion projects at the 138 kV level and below are in service or are expected to be in service before summer 2007.

For summer 2007, the WUMS Southern and Western interfaces continue to require close monitoring to ensure operation within limits when WUMS is a net importer.

Western Interface
The Eau Claire - Arpin 345 kV line continues to represent the most restrictive component of the Western interface and remains defined as an Interconnection Reliability Operating Limit (IROL). As such, it is closely monitored and managed by the Midwest ISO to no more than 790 MW. In addition the Midwest ISO conducts daily P-V analysis and establishes lower transfer limits when necessary to help prevent voltage instability. The addition of the Gardner Park - Stone Lake 345 kV line does not increase or decrease the magnitude of this IROL.

Southern Interface
The Paddock 345/138 kV transformer represents one of the more restrictive limits impacting the Southern interface. During peak load periods, steady state voltages in Southeast Wisconsin need to be closely monitored for the loss of the 345 kV line Pleasant Prairie - Racine.

Increased east to west flow bias has been observed across the northern portion of the WUMS system compared with last summer due to changes in system configuration and other conditions. High east to west transfers have the potential to cause System Operating Limit violations on the Ellington-Hintz 138 kV line for the loss of the North Appleton-Werner West 345 kV line. There is also a potential for System Operating Limit (SOL) violations due to loading at or near Sherman Street. These limits are managed with a Standing Operating Guide and through the Midwest ISO congestion management process.

The Eastern portion of Upper Michigan continues to be susceptible to abrupt Ludington pumping to generating cycle changes as well as the east to west flow bias. This limit is currently managed by opening the 69 kV lines between the Eastern portion of the Upper Michigan and the rest of the WUMS system.

Due to changes in system conditions and continued pressure of import into Upper Michigan, the 138 kV corridor consisting of the three 138 kV lines south of the Morgan and Stiles substations in the northeast Wisconsin is potentially constrained further compared with last summer. This

138 kV corridor is closely monitored and managed following an updated Standing Operating Guide, "WhiteClay-Morgan138kV_Stiles-Pulliam138kV" employing measures such as fast start of generators, manual load shedding, the Midwest ISO real time LMP/TLR congestion management, etc. For the long term, ATCLLC has planned transmission reinforcements which have been approved internally, submitted for or have received state regulatory approval and are expected to be in-service in 2009, which will strengthen the transmission system in the area significantly and mitigate the reliability concern. Some of these projects are currently under construction.

Operational Issues

Review of 2006 Summer Conditions

Moderate weather conditions in Iowa during the summer caused a moderate number of operational issues. Heavy power transfers across Iowa resulted in several eastern Iowa facilities experiencing TLR-5 calls due to post-contingency based SOL violations. Control actions were implemented to eliminate these SOL violations, including curtailment of firm schedules and generation re-dispatch. These events re-iterated the importance of recommendations of a NERC task force that was established in 2004 to investigate high power transfer levels observed through Iowa. Existing operating guides were effective in providing a sequence of control actions for Reliability Coordinators and system operators.

During peak loading periods in Nebraska, two export interfaces were monitored closely including the Cooper South (COOPER_S) Interface and the Western Nebraska to Western Kansas (WNE_WKS) Interface. During peak load periods with heavy exports to the south, NERC Transmission Loading Relief (TLR) was frequently implemented during late night and early morning hours to limit the flows on the GGS-Red Willow 345 kV line to address operating security limits associated with the WNE_WKS Interface.

During off-peak load periods in MRO, the Northern MRO region exported power to the rest of the MRO footprint and the Eastern Interconnection. Three export interfaces were monitored closely:

- Manitoba Hydro Export (MHEX)
- Minnesota-Wisconsin Stability Interface (MWSI)
- North Dakota Export (NDEX).

During periods of heavy exports to the south, congestion management was frequently implemented in the early morning hours to limit MHEX and MWSI and thus address operating security limits associated with these interfaces.
During the summer of 2006 with peak load periods in MRO, the export out of Northern MRO was reduced and therefore was not an issue.

Seams Issues

As a region, the MRO encompasses numerous operational seams including market-to-market (Midwest ISO to PJM), market-to-non market (Midwest ISO to MAPP Regional Transmission Group), and a market-to-Canadian province (Midwest ISO to Manitoba Hydro) seams. System operation and reliability coordination on each side of a seam is often conducted differently, requiring close coordination and communication. The establishment of joint operating

agreements and seams operating agreements for the purpose of real-time and projected data transfer has facilitated coordination and communication.

Congestion management events in the MRO region are evaluated by a MAPP/Midwest ISO SOA Implementation Working Group to assess accuracy, comparability, and to initiate improvements to the congestion management processes. The seams operating agreement between the Midwest ISO and MAPP addresses issues such as congestion management, redispatch, TLR procedures and reciprocally coordinated flowgates. This seams operating agreement will continue to be in place for the 2007 summer.

Environmental and Regulatory Restrictions

Environmental and regulatory restrictions are not expected to curtail availability of transmission or generation during the summer 2007 season.

Assessment Process

The MRO Reliability Assessment Committee is responsible for the summer reliability assessment. The MRO Transmission Assessment Subcommittee, MRO Resource Assessment Subcommittee, the MAPP Transmission Operations Subcommittee, the ATCLLC and SaskPower all contribute to this MRO Summer Reliability Assessment.

Reference Documents

1. Eastern Interconnection Reliability Assessment Group (ERAG) Summer 2007 Inter-regional Transmission Assessment, MRO-RFC-SERC West-SPP (MRSWS) sub-group study (on-going), http://www.maininc.org/

2. 2006 – ATCLLC 10-Year Transmission System Assessment, http://www.atc10yearplan.com

3. 2005 – ATCLLC 10-Year Transmission System Assessment, http://www.atc10yearplan.com

4. Midwest ISO Summer 2007 Assessment Studies (on-going), http://extranet.midwestiso.org/operations/seasonal.php

5. Reliability First Corporation (RFC) Summer 2007 Transmission Assessment Studies (on-going), http://www.maininc.org/

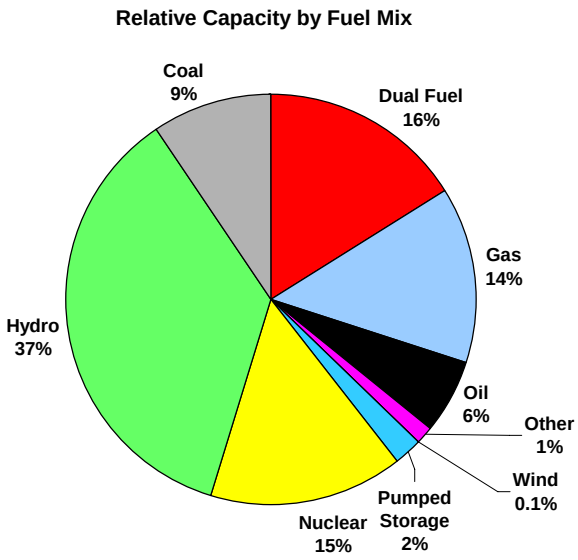
6. "System Impact Study-Council Bluffs Energy Center Unit 4", Report R1-02N, Power Technologies International, June 2002.

7. "System Impact Study Hinners Wind Farm", Report R9-06, Siemens PTI, February 2006.

The MRO region includes more than forty organizations supplying approximately 280,000,000 megawatt-hours to more than twenty million people. The MRO membership includes municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations, and independent power producers. The MRO region spans nine states and two Canadian provinces covering roughly one million square miles. Additional information can be found on the MRO Web site (www.midwestreliability.org).

NPCC

Projected Total Internal Demand	111,830	MW
Interruptible Demand & DCLM	1,940	MW
Projected Net Internal Demand	109,890	MW
Last Summer's Peak Demand	113,791	MW
Change	(1.7)	%
All-Time Summer's Peak Demand	114,207	MW
Deliverable Internal Capacity	135,470	MW
Projected Purchases and Incoming Adjustments	1,300	MW
Projected Sales and Outgoing Adjustments	182	MW
Net Capacity Resources	136,588	MW
Capacity Margin	19.5	%
Reserve Margin	24.3	%
With Uncommitted Resources		
Total Potential Resources	136,784	MW
Capacity Margin	19.7	%
Reserve Margin	24.5	%



The non-coincident aggregate 2007 summer total projected internal demand is 111,830 MW (Canadian systems 51,023 MW, U.S. systems 60,807 MW). The forecast is based on average weather conditions and is 1.7% less than last summer's non-coincident aggregate actual 113,791 MW peak demand. The forecast peak demand is very similar to last summer's 111,063 MW forecast aggregate demand.

All NPCC sub-regions (ISO New England (ISO-NE), the New York Independent System Operator (NYISO), Hydro-Québec TransÉnergie, the Ontario Independent Electricity System Operator (IESO) and the Maritimes) expect sufficient resources to be available to meet projected demands during 2007 Summer and have monthly projected net % capacity margins ranging from 10.4% to 45.9%. Québec and the Maritimes are predominately winter peaking Areas and therefore adequate resources, including the supply for firm external sales, are expected to be available. Adequate transfer capability exists to transmit surplus resources from these sub-regions to the others; however, a certain amount of bottling of resources from Québec and the Maritimes to the rest of NPCC is normal and expected.

The larger generation additions within the NPCC sub-regions that have been placed in service since the summer of 2006 include: the 100 MW Maple Ridge Wind Phase 2 Project and the 95 MW uprate of the Ginna Nuclear Plant in New York, about 190 MW of wind capacity in Ontario, three units at the Eastmain-1 Generating Station (480 MW) in Québec and the TransCanada Energy natural gas Generating Station (507 MW) in Québec. The owner of a 485 MW gas-fired generator in Ontario announced in early May that the in-service date for that generator, which had been scheduled to go into service prior to summer 2007, has been delayed beyond the summer period. Some smaller size additions are discussed in the sub-region sections.

The overall wind capacity in NPCC and associated derates on peak are highlighted in the table below.

NPCC Wind Capacity

2007 Summer Operating Season

Sub-Region	Nameplate Capacity	Credited Capacity	Capacity De-rating
Maritimes	98	18 MW	80 MW
New England	11.1 MW	4.0 MW	7.1 MW
New York	350 MW	70 MW	280 MW
Ontario	395 MW	39.5 MW	355.5 MW
Québec	322 MW	0 MW	322 MW

Transmission additions for 2007 summer include: first stage of the NSTAR 345 kV Reliability Project that involves the addition of two new 345 kV underground cables from Stoughton, Massachusetts into the Boston area (The first cable was energized in the autumn of 2006 and the second was energized in late April 2007), the Plumtree-Norwalk 345 kV circuit in southwest Connecticut (went into service in October 2006), a new 345 kV line in Vermont that is a portion of the Northwest Vermont Reliability Project (in-service), the 660 MW Neptune HVDC Cable that extends between PJM and Long Island (planned for the summer of 2007), a new Mott Haven 345 kV substation in New York City serving load in the Bronx, between Dunwoodie and Rainey substations (planned for the summer of 2007), upgrades in the Rochester, NY vicinity (planned for the summer of 2007), the 735/315 kV 1,100 MVA transformer at Arnaud Transformer Station in Québec (in service) and a 345 MVAR 315-kV capacitor bank at the Hertel 735/315-kV substation in the Montreal area (in service). These should all provide significant system reliability improvements.

In past years, the Southwest Connecticut (SWCT) area has faced reliability problems due to transmission constraints into and within that region. However, the addition of Phase 1 of the 345 kV Southwest Connecticut Reliability Project in October 2006 increased the import capability into that region to 2,350 MW. With Phase 1 in service, it is anticipated that the combined ability of the electric generating resources in the area and the available transmission capacity to import electric energy into the region will be adequate to meet the demand in Southwest Connecticut. Phase 2 of the Southwest Connecticut Reliability Project, which transmission owners plan to put in service in 2009, will further increase the import capability by 1,300 MW.

A high-voltage shunt capacitor at Richview TS in the Toronto, Ontario vicinity suffered significant damage recently and is not expected to return to service before summer 2007. As a result of its investigation into the capacitor failure, the transmitter, Hydro One, has imposed temporary restrictions on the use of high voltage shunt capacitors across the province. With the exception of the damaged capacitor at Richview TS, Hydro One has developed plans to enable other high voltage shunt capacitors to return to normal operations. Hydro One is working with suppliers to acquire the necessary materials to complete this work before summer 2007. A risk

exists that some capacitors may not be available and some may continue to require operating restrictions into the summer.

With the return to service of the Scott-Bunce Creek B3N 230 kV circuit on November 15, 2006 after a 3 ½ year outage resulting from prolonged land-use deliberations, all four Ontario-Michigan ties are in service with Phase Angle Regulators (PARs) in place in the other three circuits. The PARs are not available to regulate flows except in emergencies, pending agreement by the International Transmission Company in Michigan to permit full regulation.

A detailed summary of the expectations of each of the NPCC sub-regions follows:

Sub-regions

Maritimes

Demand — Based on the Maritimes Area 2007 demand forecast, a peak of 3,738 MW is predicted to occur for the summer period, June through September. The actual peak for summer 2006 was 3,356 MW on July 17, 2006, which was approximately 382 MW (11.29%) lower than last year's forecast of 3,735 MW. The reduction in demand was due to a combination of higher than normal temperatures, resulting in a lower electric heating load in September 2006, and a reduction of approximately 200 MW of industrial load due to a labor dispute.

The Maritimes Area load is the mathematical sum of the forecasted weekly peak loads of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). As such, it does not take the effect of load coincidence within the week into account. If the total Maritimes Area load included a coincidence factor, the forecast load would be approximately 1-3% lower.

The New Brunswick System Operator uses a load forecast based on an End-use Model (sum of forecasted loads by use e.g. water heating, space heating, lighting etc.) for residential loads and an Econometric Model for general service and industrial loads, correlating forecasted economic growth and historical loads. Each of these models is weather adjusted using a 30-year historical average.

For Nova Scotia, the load forecast is based on a 30-year historical climate normal for the major load center, along with analyses of sales history, economic indicators, customer surveys, technological and demographic changes in the market, and the price and availability of other energy sources.

For Prince Edward Island, the load forecast uses average long-term weather for the peak period (typically December) and a time-based regression model to determine the forecasted annual peak. The remaining months are prorated on the previous year.

The Northern Maine Independent System Administrator performs a trend analysis on historic data in order to develop an estimate of future loads.

Load Management is not included in the resource adequacy assessment for the Maritimes Area.

In the Maritimes Area there is between 549 MW and 567 MW of interruptible demand available during the assessment period; there is 560 MW forecasted to be available at the time of the seasonal peak.

Recognizing that it is a predominantly winter peaking system, the Maritime Area did not address extreme weather in its 2007 summer assessment.

Resources — The Maritimes Area projected capacity margins based on net capacity resources for the assessment period ranging from 40% to 46%. When allowances for unplanned outages (based on a discreet MW value representing an historical assessment of the total forced outages in MW typically realized at the time of peak for the given operating season) are considered, the Maritimes Area is projecting more than adequate surplus capacity margins above its operating reserve requirements for the Summer 2007 assessment period. These surplus margins range from 29% to 52% over the period from June 2007 through September 2007. This range is similar to the corresponding 2006 summer projection. The Maritimes Area is a winter peaking system and resource adequacy is generally not a concern during the summer operating period.

There are no firm purchases from other regions currently designated/scheduled by any loads in the Maritimes Area during the assessment period. There are 200 MW of firm sales included in the resource adequacy assessment.

Included in the Internal Capacity for each of the months in the summer assessment period is an additional 18 MW of wind generation to be in-service by June 1, 2007.

The Maritimes Area is forecasting normal hydro conditions for the Summer 2007 assessment period. The Maritimes Area hydro resources are run of the river facilities with limited reservoir storage facilities. These facilities are primarily utilized as peaking units or for providing operating reserve.

In the Maritimes Area deliverability of generation to load is not a concern, operationally, as there are no transmission constraints or zonal issues within the area.

The NPCC report "2005 Maritimes Interim Review of Resource Adequacy" identified that the Maritimes met the NPCC resource adequacy reliability criterion in years 2006 to 2008 without requiring any external assistance. In 2009, the report identified that the Maritimes Area requires an additional 20 MW to meet the criterion, but this is well within the 1,500 MW import capability of the Maritimes.

Fuel —The fuel supply in the Maritimes Area is very diverse and includes nuclear, natural gas, coal, oil (both light and residual), petroleum coke, Orimulsion, hydro, tidal, municipal waste, and wood. Fuel supplies are expected to be adequate during the projected peak summer demand. Extreme weather conditions should have no impact on the fuel supply to the Maritimes Area.

For the summer of 2007, the Maritimes Area will have 98 MW of wind generation in service, of which 18 MW will be counted in its capacity data.

Transmission — No major transmission additions have been made to the Maritimes system since the 2006 summer and no planned changes are anticipated for summer 2007.

In the Maritimes Area deliverability of generation to load is not a concern, operationally, as there are no transmission constraints or zonal issues within the area.

Inter-Area transmission transfer capability studies are conducted seasonally.

Operational Issues — There are no major generating unit or transmission facility outages anticipated for the summer that will impact reliability in the Maritimes Area. There are no environmental or regulatory restrictions that could impact reliability in the Maritimes Area. There are no unusual operating conditions anticipated for the summer that will impact reliability in the Maritimes Area.

New England

Demand — ISO New England's Balancing Authority reference peak load forecast for the summer of 2007 is 27,360 MW. This is 335 MW (1.2%) higher than the 2006 summer projected peak of 27,025, 770 MW (2.7%) lower than the 28,130 MW actual 2006 summer peak load that occurred on August 2, 2006 and 420 MW (1.6%) higher than the weather normalized 2006 summer peak load of 26,940 MW. The key factors leading to the higher forecast in 2007 are continuing increases in peak response to temperature and humidity, underlying demographic and economic growth (in 2007 households are projected to grow by 0.7%, and real income per household is expected to grow by 2.1%), and smaller electric price increases assumed in developing the 2007 forecast as compared to those used to develop the 2006 forecast.

The reference case forecast is the 50/50 forecast (50% chance of being exceeded), corresponding to a New England 3-day weighted temperature-humidity index (WTHI) of 80.1 which is equivalent to a dry bulb temperature of 90 degrees Fahrenheit and a dew point temperature of 70 degrees Fahrenheit. The 80.1 WTHI is the 95th percentile of a weekly weather distribution and is consistent with the average of the WTHI value at the time of the summer peak over the last 30 years.

A total of 828 MW of demand resources that could be interrupted during times of capacity shortages is assumed available for the summer of 2007. Not included in this assessment is voluntary load that will interrupt based on the price of energy. As of March 1, 2007, there are approximately 106 MW enrolled in this program. Their actual interruptions are captured in historical data; in the summer of 2006, this figure was about 50 MW.

Interruptible demand in the ISO-operated Demand Response programs must be available to interrupt between 7 a.m. and 6 p.m., Monday through Friday, non-holidays. These resources must be capable of interrupting their demand on either 30 minutes or 2 hours notice, depending upon the program. They are instructed to interrupt their consumption during specific actions of Operating Procedure No. 4 (OP 4) *Action during a Capacity Deficiency*. OP 4 may be found on ISO-NE's website at http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html. In general, these loads are available for interruption coincident with the system peak.

ISO-NE has some assets in its Real-Time Demand Response programs that are under direct load control. The direct load control involves the interruption of central air conditioning systems in residential, commercial and industrial facilities.

Demand side management programs include utility programs that reduce customer load during many hours of the year. Examples include utility rebate and shared savings programs for the installation of energy efficient appliances, lighting and electrical machinery, and weatherization programs. Generally, load management is not dispatchable by the ISO or the local utility; rather it represents customer load reductions that are present by the simple use of the measures installed. These reductions from existing demand side management programs are included in the historical data that are used in ISO-NE's load forecasting model.

ISO New England addresses peak demand uncertainty in two ways:

- Weather — peak load distribution forecasts are made based on 37 years of historical weather which includes the reference forecast (5% chance of being exceeded), and extreme forecast (10%chance of being exceeded);
- Economics — alternative forecasts are made using high and low economic scenarios.

ISO New England is concerned with meeting the extreme, 90/10 peak demand based on the reference economic forecast. For summer 2007, that value is 29,165. The projected capacity margin based on net capacity resources under the high case demand forecast is over 2,438 MW and the corresponding % capacity margin is 7.9%. This projected margin is sufficient to cover the New England operating reserve requirement of approximately 1,800 MW.

Resources — During the summer peak load period, ISO New England projects a capacity margin based on net capacity resources of 4,243 MW (lowest value projected in June), which is (13.8%) under the reference case demand forecast. This projected margin is sufficient to cover the New England operating reserve requirement, which is approximately 1,800 MW; however, higher than expected unit outages and/or higher than anticipated load could adversely affect the forecasted margin.

The forecasted 2007 margin is about 1,000 MW higher than the actual capacity margin that was experienced in August 2006, the month when the summer peak load occurred.

ISO New England does not typically experience fuel supply or delivery problems during the summer. However, the ISO could experience higher than anticipated unavailability due to high temperatures. The ISO takes forced outages into consideration in its operable capacity analysis, and typically assumes an allowance of 2,100 MW for unplanned outages during the summer months. With this additional unavailable capacity, the installed capacity margin under the reference case forecast would still be 2,140 MW. The total nameplate capability of wind generators in New England is for the summer period is 11.1 MW, while the amount claimed for capability is approximately 4.0 MW (36% of nameplate).

The forecast of monthly summer firm external capacity purchases is 401 MW. This includes 310 MW from Hydro-Québec and 91 MW from New York. Only firm purchases that are known in

advance are included as capacity. A 330 MW sale to New York on the Cross Sound Cable will also be in effect.

ISO New England does not include energy-only, uncommitted resources, or transmission-limited resources in its resource adequacy assessment.

A total of 96 MW of new committed capacity is expected to be placed in service during the summer: 7 MW by July 1st and 89 MW more by September 1st.

Hydro conditions are anticipated to be sufficient to meet the expected demand this summer. Hydro generation contributes approximately 5% of the total New England generation, and reservoir levels are expected to be normal for the upcoming summer.

For the summer of 2007, ISO-NE does not anticipate transmission constraints that will affect New England regional reliability. However, concerns remain in the transmission import capability in three major load pockets: Southwest Connecticut, Greater Connecticut and the city of Boston. The sub-area of Southwest Connecticut is defined geographically by 54 towns in southwestern Connecticut, which are generally bounded by Interstate Highway 91 to the east and Interstate Highway 84 to the north. The Greater Connecticut sub-area combines the Norwalk, Southwest Connecticut, and Connecticut sub-areas; this sub-area has similar boundaries to the physical boundaries of the state of Connecticut, but it is slightly smaller because of electrical system limitations near the borders with western Massachusetts and Rhode Island.

In past years, the Southwest Connecticut (SWCT) area has faced reliability problems due to transmission constraints into and within that region. However, the addition of Phase 1 of the 345 kV Southwest Connecticut Reliability Project in October of 2006 increased the import capability into that region to 2,350 MW, an increase of 350 MW. With Phase 1 in service, it is anticipated that the combined ability of the electric generating resources in the area and the available transmission capacity to import electric energy into the region will be adequate to meet the demand in Southwest Connecticut. The margin for Southwest Connecticut in the summer of 2007 will be 148 MW, assuming extreme loads for the sub-area (about 3,900 MW) and the loss of the largest resource contingency (451 MW). The normal load forecast for the area is about 3,700 MW. Phase 2 of the Southwest Connecticut Reliability Project, which transmission owners plan to put in service in 2009, will further increase the import capability by 1,300 MW.

The *ISO New England Regional System Plan 2006* (RSP06) is posted on ISO-NE's website at http://www.iso-ne.com/trans/rsp/2006/rsp06_final_public.pdf. That plan indicates that resource adequacy studies show Greater Connecticut is a major load pocket that has an immediate need for resources, transmission improvements, or both. The projected capacity margin in Greater Connecticut is expected to remain negative in 2007 according to the RSP06 study results. Since the publication of RSP06 and in response to the Forward Capacity Market (FCM) and its Settlement Agreement, over 200 MW of Demand Response resources in Connecticut have been added, which would help to meet that area's summer 2007 resource needs. Furthermore, with the planned implementation of the Forward Capacity Market in June 2010, there will be a local sourcing requirement for Connecticut. If ISO-NE determines that resources are inadequate to supply load, ISO-NE will buy resources to be installed in that area. If local resources and

imports into Connecticut are still insufficient to meet the need, it is anticipated that system operators would rely on the implementation of Operating Procedure No. 4, *Action During a Capacity Deficiency* in Greater Connecticut to maintain local and regional system reliability. In the longer term, transmission solutions that will improve the ability to transfer power between Rhode Island, Massachusetts and Connecticut have been developed and are currently being finalized. These solutions will eliminate constraints into the Greater Connecticut load pocket and are estimated to be placed in service in the 2010 to 2013 time frame.

The Boston sub-area, a major demand center in New England, is another area where reliability has been a concern in recent years. The NSTAR 345 kV Transmission Reliability Project is allowing increased imports of power into the area. The first of the NSTAR 345 kV Stage 1 cable additions became operational in October 2006 and the second cable was energized in late April 2007. With the addition of the two cables the transmission import capability into the Boston area is increased by approximately 1,000 MW (to 4,600 MW total). RSP06 forecasted a positive load margin for the Boston area in summer 2007 as a direct result of the NSTAR project. The margin for the Boston sub-area in the summer of 2007 will be 765 MW, assuming the extreme load forecast for the sub-area (5,830 MW) and the loss of the largest resource contingency (1,200 MW). The normal load forecast for the sub-area is 5,490 MW.

Historically, fuel supply and delivery options have been readily available to generators within New England during the summer months. For the summer of 2007, ISO-NE does not foresee any fuel supply or delivery problems.

Transmission

- The first stage of the NSTAR 345 kV Reliability Project involves the addition of two new 345 kV underground cables from Stoughton, Massachusetts into the Boston area, providing a much needed increase in import capability for this area. The first of those cables was placed into service in October 2006. During testing on the second cable, a fault occurred. This cable was recently repaired, tested and energized. The first stage of the project addresses Boston-area reliability problems and increases the Boston-import transfer capability by approximately 1,000 MW.
- Phase 1 of the Southwest Connecticut 345 kV project, which includes a 20-mile Plumtree-Norwalk 345-kV circuit from Bethel to Norwalk, became operational in October 2006. This is the first phase of a project that addresses the reliability needs in Greater Southwest Connecticut, including the need to address operating constraints.
- A new 345 kV line in Vermont became operational in January 2007. This is a portion of the Northwest Vermont Reliability Project, which addresses the reliability needs in the northwestern area of Vermont.
- A new 345-kV substation will be constructed interconnecting to the existing 115-kV Wachusett substation in central Massachusetts. This new substation provides an additional supply into the central Massachusetts 115-kV network and unloads other area autotransformers.
- The Monroe converter station was retired on March 31, 2007, resulting in decommissioning of the United States portion of the Phase I HVDC terminal

facilities. Four 20 MVAR banks of switched shunt reactors, four 31.5 MVAR banks of switched capacitors, and equipment necessary for continued operation the Phase II HVDC facilities will remain in service. The Phase I retirement is not expected to have a significant adverse effect on transmission system stability, reliability or operating characteristics.

There are no new flow patterns due to new generation or power transfers into, out of, or through the New England Area.

At this time, there are no issues or concerns that could impact the reliable operation of the New England bulk power transmission system for the coming summer. Deliverability problems into the Southwest Connecticut and Boston load pockets have been a concern in New England. The completion of the first Phase of the 345 kV Reliability Projects in both Southwest Connecticut and Boston have provided increases the transmission capacity available to import electric energy into those sub-areas.

ISO-NE and Inter-Area transmission transfer capability studies are conducted seasonally. Part of the process in any of ISO-NE's studies involving transmission changes or generator interconnections is to ensure that existing transfer capabilities are maintained.

Operational Issues — No significant generating unit or transmission facility outages that could impact reliability are anticipated for the summer. ISO-NE's Outage Coordination staff reviews the proposed maintenance schedules for generators and calculates the weekly Long Term Operable Capacity Margin, LTOCM, as defined in ISO New England Operating Procedure No. 5 (OP-5). OP 5 is posted on ISO-NE's website.[17] Requests for Planned Outages during any weeks when the LTOCM is negative during the months of June, July and August are denied. Also, it is recognized that since there is a significant amount of capacity scheduled out of service during late spring, the possibility of outage overruns into the summer period may exist. For this reason, the expected return date for these generators will be regularly verified and updated to prepare for the summer period.

Generating resource performance due to environmental and/or regulatory restrictions has been captured in the ISO's unit availability assumptions. No additional environmental and/or regulatory restrictions are anticipated to impact reliability during the 2007 summer period. In addition, ISO New England does not anticipate any unusual operating conditions that could impact reliability for the upcoming summer.

New York

Demand — The New York Area peak demand forecast for the 2007 Summer Operating Period is 33,447 MW, which is 152 MW higher than the forecast of 33,295 MW for the 2006 Summer Operating Period. This forecast demand is 1.4 % lower than the all-time summer peak of 33,939 MW that occurred on August 2, 2006. The daily peak demand observed by New York during the Summer Operating Period occurs in the mid to late afternoon. The forecast is developed by the NYISO using a Temperature-Humidity Index (THI) value of 84.2 degrees, which is representative of weather conditions during peak load conditions. At forecast demand levels, a

[17] http://www.isone.com/rules_proceds/operating/isone/op5/index.html

one-degree increase in the THI will result in approximately 610 MW of additional load. Under extreme conditions the peak demand could reach 35,000 MW.

The NYISO introduced two load response programs for the New York Market in May 2001. The Special Case Resource (SCR) and Emergency Demand Response Program (EDRP) are programs in which Customers are paid to reduce their consumption by either interrupting load or switching to emergency standby generation when requested by the NYISO.

The EDRP is continuing for summer 2007, and NYISO estimates that 228 MW of load relief during peak conditions is considered reliable. This load relief will be available to support the New York State power system during capacity emergency periods. This program is in addition to the relief obtained through the emergency procedures for Operating Reserve Peak Forecast Shortage (Section 4.4.1 NYISO Emergency Operations Manual) or in response to the major emergency state (Section 3.2 NYISO Emergency Operations Manual). Additionally, SCR is expected to provide 1,080 MW of load relief under peak conditions.

Resource Assessment — NYISO conducts semi-annual and monthly Installed Capacity (ICAP) auctions. Based on the forecast load for 2007, the ICAP requirement is 38,966 MW based on a 16.5% Installed Reserve Margin (IRM) requirement. In 2006 the IRM requirement was 18%. In March 2007, the New York Public Service Commission issued an order accepting the New York State Reliability Council's filing of a 16.5% IRM for the State of New York. In addition to the generation resources within the New York Area, generation resources external to the New York Area can also participate in the NYISO ICAP market. An external ICAP supplier must declare that the amount of generation that is accepted as ICAP in New York will not be sold elsewhere. The external Area in which the supplier is located has to agree that the supplier will not be recalled or curtailed to support its own loads; or will treat the supplier using the same pro rata curtailment priority for resources within its Balancing Area. The energy that has been accepted as ICAP in New York must be demonstrated to be deliverable to the New York border. The NYISO sets a limit on the amount of ICAP that can be provided by suppliers external to New York. Resources within the New York Area that provide firm capacity to an entity external to the New York Area are not qualified to participate in the ICAP market. When allowances are taken for unplanned outages (based on historical performance of 9.1 % unavailable capacity), the net available resources will be 35,419 MW, which will be sufficient to meet the New York Area load and operating reserve requirement during the peak load hours, with a reserve margin of approximately 172 MW expected at peak conditions.

The forecast of monthly summer firm external capacity purchases is 2,735 MW. This includes 1,300 MW from PJM, 1,105 MW Hydro-Québec and 330 MW from New England. Sales are 273 MW.

Based on the RAS assessment methodology calculation, which account for purchases and sales, the New York net capacity resources are projected to be 40,283 MW and the net internal demand is 33,447 MW. That results in a net capacity resource margin of 6,836 MW and a capacity margin based on net capacity resources of 17%.

Since the summer of 2006, 195 MW of additional resources have been added to the New York system. These additions include the 100 MW Maple Ridge Wind Phase 2 Project and the 95 MW uprate of the Ginna Nuclear Plant.

Fuel — Traditionally, the New York Area generation mix has been dependent on fossil fuels for the largest portion of the installed capacity. Recent capacity additions or enhancements now available use natural gas as the primary fuel. While some existing generators in southeastern New York have dual-fuel capability, use of residual or distillate oil as an alternate may be limited by environmental regulations. Adequate supplies of all fuel types are expected to be available for the summer period. The distribution of fuel in New York is as follows:

New York State's Fuel Mix

Fuel Type	%
Natural Gas	16%
Natural Gas & Oil	38%
Oil	8%
Coal	8%
Hydro	15%
Nuclear	13%
Wind	1%
Other	1%

For the summer of 2007, New York will have 350 MW of wind generation in service, of which 70 MW will be counted in its capacity data.

Transmission — A new 345 kV substation in New York City serving load in the Bronx, Mott Haven, is planned for the summer of 2007 between Dunwoodie and Rainey. Upgrades in the Rochester vicinity are planned in anticipation of the Russell Station retirement this summer. The Neptune HVDC Cable, which extends between PJM and Long Island and has a 660 MW rated capacity, is planned for service in July 2007.

No other major flow pattern changes and no deliverability concerns are anticipated.

The NYISO conducts transfer capability studies and participates in regional and interregional studies to ensure adequate import and export transfer capability exists.

Operational Issues — No significant generating unit or transmission facility outages that could impact reliability are anticipated for the summer. No environmental and/or regulatory restrictions are anticipated to impact reliability during the 2007 summer period. NYISO does not anticipate any unusual operating conditions that could impact reliability for the upcoming summer.

Ontario

Demand — Ontario's forecast summer peak demand is 25,516 MW based on monthly normalized weather. The forecast peak for summer 2007 is 5.5% lower than the 27,005 MW actual peak

demand which occurred on August 1st, 2006 under extreme weather conditions. Over 3,000 MW of this demand was due to the higher than average heat and humidity.

The 2007 forecast is 1.7% higher than last summer's weather-corrected peak demand of 25,078 MW. The extent of the increase is due to strong economic growth which is somewhat offset by lagging growth in large energy intensive industries.

The IESO quantifies the uncertainty in peak demand due to weather variation. Load Forecast Uncertainty (LFU) represents the impact on demand of one standard deviation in the underlying weather parameters. For the upcoming summer peak of 25,516 MW the LFU is 1,192 MW. The extreme weather forecast is projected to be 27,575 MW for the summer of 2007. This is based on the most extreme combinations of temperature, humidity, wind speed and cloud cover experienced in Ontario over the time frame 1970 to 2006. Should this extreme weather condition be realized, available imports are expected to be sufficient to meet the Ontario demand,

A sizeable number of loads within the province bid their load into the market and are responsive to price and to dispatch instructions. Other loads have been contracted by the Ontario Power Authority to provide demand response under tight supply conditions. The combined amount of these demand measures has been steadily increasing and now amounts to approximately 845 MW of which 552 MW is assumed to be available at time of peak and included for seasonal capacity planning purposes.

Resource Assessment — Resources available within Ontario together with imports are forecast to be adequate to meet demand and energy requirements during the summer period. Projected operable total internal capacity is about 1,500 MW higher than last summer and total potential resources are about 500 MW higher than the 2006 summer level. The capacity margin based on net capacity resources is 10.4% the same as the 10.4% reported for 2006 summer. As indicated above the extreme forecast demand for the summer is about 27,500 MW and the capacity margin based on net capacity resources at that demand level is about 3.0%. Planning reserves, determined on the basis of IESO's requirements for Ontario self-sufficiency, are above target levels for all weeks in this period except for a week each in June and July. There are no firm sales projected for the 2007 summer period. Reliance on imports for modest shortfalls in these two weeks is expected to be sufficient to ensure demand and operating reserve requirements.

Since last summer, more than 200 MW of new capacity was made available to the Ontario power system. This new capacity includes about 190 MW of wind capacity, 25 MW in the form of upgrades to two existing generators and 5 MW from a landfill gas fired station. The owner of a 485 MW gas-fired generator in Ontario announced in early May that the in-service date for that generator, which had been scheduled to go into service prior to summer 2007, has been delayed beyond the summer period.

Energy supplies available within Ontario are expected to be adequate overall, but energy deficiencies could arise as a result of higher than forecast forced outage situations, prolonged extreme weather conditions and other influencing factors. Available imports are expected to be sufficient to ensure summer energy demands can be met for a wide variety of conditions.

IESO plans for Ontario to meet NPCC adequacy criteria do not include reliance on external resources. External resources are normally procured on an economic basis through the IESO-administered markets. Alternatively, market participants may arrange limited external purchases of capacity to avoid deferral or cancellation of generator outages in the event that operating reserve deficiencies are forecast in the near-term.

Fuel — The Ontario fuel supply infrastructure is judged to be adequate during the summer peak demand, and there are no fuel delivery problems anticipated for this summer. Reservoir levels are expected to be adequate to maintain hydroelectric generation.

IESO requires generator market participants in Ontario to provide specific information regarding energy or capacity impacts if fuel-supply limitations are anticipated. In general, fuel delivery infrastructure redundancy for non-renewable resources such as coal, uranium, oil and gas is robust and more explicit analysis is considered only on an ad hoc basis.

In anticipation of growing amounts of gas-fired generation in Ontario over the coming years, the Ontario Gas Electric Interface Working Group (OGEIWG) was formed with various stakeholders. The group is establishing communication protocols and a framework for contingency analysis in order to manage operational and reliability issues in both energy sectors. Earlier work by this group provided cross-functional training and pipeline input on gas-electric day coordination relative to design of an electricity day-ahead market in Ontario.

For the summer of 2007, the Ontario Area will have 395 MW of wind generation in service, of which 39.5 MW will be counted in its capacity data.

Transmission Assessment — The Ontario transmission system is expected to be adequate to supply the coming summer's demand under the forecast conditions. A high-voltage shunt capacitor at Richview TS suffered significant damage recently and is not expected to return to service before summer 2007. As a result of its investigation into the capacitor failure, the transmitter, Hydro One, has imposed temporary restrictions on the use of high voltage shunt capacitors across the province. With the exception of the damaged capacitor at Richview TS in the Toronto vicinity, Hydro One has developed plans to enable other high voltage shunt capacitors to return to normal operations. Hydro One is working with suppliers to acquire the necessary materials to complete this work before summer 2007. A risk exists that some capacitors may not be available and some may continue to require operating restrictions into the summer.

The first phase of a major manufacturing development in the Woodstock area, which is located in southwest Ontario, is planned in service by summer 2007. The new load will increase the stresses on the transmission which might result, during extreme weather conditions, in very low voltages in the area. To alleviate these concerns Hydro One is planning to add a second supply point to the area by extending the 230 kV transmission lines from Ingersoll to Woodstock area and installing a new transformer station. This plan will provide an increased level of supply reliability and support further load growth in the area. No other major flow pattern changes and no deliverability concerns are anticipated.

All four Ontario-Michigan ties are in service with the return to service of the Scott-Bunce Creek B3N 230 kV circuit on November 15, 2006 after a 3 ½ year outage. Phase Angle Regulators

(PARs) are in place in the other three circuits. The PARs are not available to regulate flows except in emergencies, pending agreement by the International Transmission Company in Michigan to permit full regulation. The inability to regulate flows combined with limiting ratings on the PAR equipment can result in significant congestion of imports from Michigan. This was experienced in summer 2005. Before summer 2006, the IESO, the Midwest ISO, Hydro One and International Transmission Company, agreed to temporarily bypass the phase angle regulators for normal operation until an agreement is reached to make full use of their regulating capability. Bypassing the PARs increases Ontario's transfer capability to and from Michigan by 300 to 350 MW in the summer.

IESO conducts transfer capability studies and participates in regional and interregional studies to ensure adequate import and export transfer capability exists.

Operational Issues — 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 and forecast energy limitations have been included in the IESO's adequacy assessment.

Assessment Process — The IESO uses a multi-area resource adequacy model, in conjunction with power flow analyses, to determine the deliverability of resources to load. This process is described in the document, "*Methodology to Perform Long-Term Assessments*", posted on the IESO web at http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp

Québec

Demand — The Hydro-Québec peak demand forecast for the summer of 2007 is 21,769 MW. This is about the same as the 2006 summer projected peak (21,778) and is about 400 MW higher than the observed peak demand of 21,379 MW, which was about 200 MW below the Québec all-time summer peak. A downward reappraisal of economic growth for the year 2007 ─ particularly in the manufacturing sector ─ is the principal cause of the flat demand growth indicated by the forecast.

The forecast is based on normal weather assumptions that use a 30-year span of historical weather conditions. No changes have occurred in the normalization procedure since last year. The 2007 summer forecast ─ based on a certain number of economic, demographic and energy-use assumptions ─ was presented in the second follow-up of the Hydro-Québec Distribution (HQD) Procurement Plan submitted to the Québec Energy Board in October 2006. Since last year, the major change comes from the downward revision of economic growth, especially in the manufacturing sector.

In Québec no interruptible load programs are available for the summer period. Last year, an amount of 720 MW of load was included in the balance sheet because the program was effective for an entire reference year, December 1st to November 30th of the next year. The program is now effective for the winter period only (4 months), December 1st to March 31st of the next year.

Hydro-Québec has developed hourly chronological load profiles based on a 30-year analysis of historical weather conditions (1971-2000). This methodology is useful to quantify weather

uncertainty and its impacts on peak demand. Since Québec has a winter peaking load profile, the uncertainty – measured by a standard deviation analysis – is lower during the summer than during the winter. As an example, at the summer peak, weather condition uncertainty is about 300 MW, equivalent to one standard deviation. During winter, this uncertainty is approximately 1,200 MW. Extreme weather deviations can be quantified at about 1,100 MW for the summer peak and at about 4,400 MW for the winter peak.

Resources — Hydro-Québec reserve margins are expected to be around 10,000 MW for summer 2007. This represents 46 % of the net internal demand. This excess capacity is due to the fact that the Québec Area is a winter peaking system. For the winter period, to respect the NPCC resource adequacy criteria, the reserve margin must be around 10 %.

There are three main capacity changes from last year's summer assessment:

- The three units at the Eastmain-1 Generating Station are now available (480 MW) compared to one 160 MW unit that had been available in September 2006;
- The TransCanada Energy natural gas Generating Station (507 MW) is fully available for the entire 2007 summer period whereas in 2006, it had been available starting from September only;
- The hydro-unit maintenance program is reduced between 700 and 1,800 MW compared to last summer's maintenance program.

Resource unavailability is not a concern in Québec since about 95% of resources are hydro-electric.

The sales and purchases include a 200 MW purchase from New Brunswick, a 1,105 MW sale to New York, a 310 MW sale to New England and a 145 MW sale to Cornwall municipal (in southeast Ontario). All have firm contracts in place for both capacity and transmission.

The only Québec capacity addition projected for the summer is the 32 MW Mercier hydro generating station.

To demonstrate its energy reliability Hydro-Québec presents an energy reliability assessment to the Québec Energy Board three times a year. Hydro-Québec Production is the generation division of Hydro-Québec and Hydro-Québec's reservoirs' manager. Its energy reliability criterion states that Hydro-Québec Production must maintain a sufficient energy reserve to protect against a possible hydraulic deficit of 64 TWh upon two consecutive years and 98 TWh upon four consecutive years. The last assessment produced by Hydro-Québec for the Québec Energy Board shows that Hydro-Québec Production complies with this energy reliability criterion.

To access Hydro-Québec Production's last energy assessment, refer to http://www.regie-energie.qc.ca/audiences/CriteresFiabilite/HQ_CriteresFiab_AnnexeB_01dec06.pdf

There are no deliverability concerns during the summer period in the Québec Area.

Fuel — The Québec sub-region does not consider potential fuel-supply interruptions in the regional assessment. The reason for this is that non-hydraulic resources account only for a very small portion (about 5%) of total resources. Hydro-Québec is currently developing a formal methodology to de-rate the capacity provided by installed wind generation; for the summer of 2007, HQ is assuming 322 MW of wind de-ratings.

Transmission — Since last summer, several transmission projects have been placed in service in Québec:

- The two remaining Eastmain 1 13.8/315 kV, 166 MVA transformers required to integrate the two last Eastmain 1 generators in northwestern Québec.
- The 735/315 kV, 1,100 MVA transformer at Arnaud Transformer Station to improve local load supply in northeastern Québec.
- A new 345 MVAR, 315 kV capacitor bank at Hertel Transformer Station to improve voltage support in the Montréal area.

This coming summer, a few minor upgrades on the Matapédia subsystem (eastern Québec) will be made to integrate new wind power generation, scheduled to be in service near the end of 2007.

No transmission constraint, flow pattern changes or deliverability problems are anticipated.

Interconnection transmission capability studies are conducted periodically with Québec's neighboring systems to assess interconnection limits. During summer, the Québec Area does not expect to need external assistance. However, the "NPCC Reliability Assessment for Summer 2007" evaluates transfer capabilities between NPCC Areas. A certain amount of bottling of resources from Québec and the Maritimes to the rest of NPCC is expected and discussed therein.

Operational Issues — Lines 3078/3079 from Lévis to Rivière-du-Loup are out of service from July 2 to October 12. Work to be done on those lines is mechanical reinforcement of towers and conductors. This will impact transfer capability to New-Brunswick. No major generating unit outages are anticipated for the summer. No unusual operating conditions that could impact reliability are anticipated for the upcoming summer. In addition, no environmental and/or regulatory restrictions that could potentially impact reliability are expected.

Import capability on the Phase I HVDC interconnection from Monroe (New England) to Des Cantons (Québec) is down from 690 MW to 0 MW due to the retirement of Monroe. No adverse impact is anticipated on Québec reliability for the 2007 Summer Operating Period. However, TransÉnergie, together with National Grid, will study the possibility of operating the interconnection using Sandy Pond with Des Cantons in import mode into Québec. This would allow TransÉnergie to operate Radisson – Nicolet for its own needs in winter while importing from Sandy Pond through Des Cantons if needed.

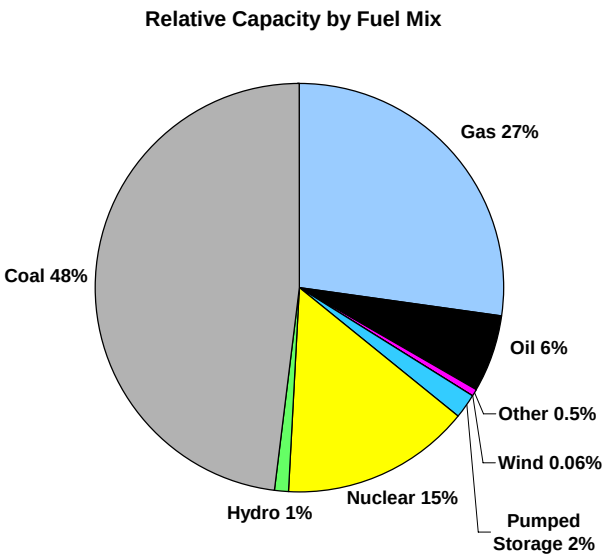
The Northeast Power Coordinating Council, Inc. (NPCC Inc.) is the international Regional Reliability Organization (RRO) for Northeastern North America. Its purpose is to promote the reliable and efficient operation of the international, interconnected bulk power systems in

Northeastern North America through the establishment of regionally-specific criteria, coordination of system planning, design and operations, assessment of reliability and monitoring and enforcement of compliance with such criteria, and other applicable criteria. In the development of reliability criteria, NPCC Inc., to the extent possible, facilitates attainment of fair, effective and efficient competitive electric markets. NPCC Inc. is a non-for-profit New York corporation. The geographic area covered includes New York, the six New England states, and Ontario, Quebec, and Maritime Provinces in Canada. The total population served is approximately 56 million over approximately 1 million square miles.

NPCC was originally formed shortly after the 1965 Northeast Blackout to promote the reliability and efficiency of the interconnected power systems within its geographic area. NPCC restructured in response to U.S. energy legislation signed into law August, 2005, in preparation for the certification of an Electric Reliability Organization (ERO) and subsequent execution of a Regional Delegation Agreement and Memorandums of Understanding with appropriate Canadian Provincial regulatory and governmental authorities. Membership interests were transferred to NPCC Inc., and a separate and independent, affiliated, not-for-profit corporation, NPCC: Cross-Border Regional Entity, Inc. (NPCC CBRE). NPCC CBRE will perform functions delegated or contracted to it from the ERO, to be backstopped by the Federal Energy Regulatory Commission (FERC) and Canadian Provincial authorities. Additional information can be found on the NPCC Web site (http://www.npcc.org/).

RFC

Projected Total Internal Demand	183,400	MW
Interruptible Demand & DCLM	3,800	MW
Projected Net Internal Demand	179,600	MW
Last Summer's Peak Demand	190,800	MW
Change	(3.9)	%
All-Time Summer's Peak Demand	190,800	MW
Deliverable Internal Capacity	213,065	MW
Projected Purchases and Incoming Adjustments	2,091	MW
Projected Sales and Outgoing Adjustments	1,364	MW
Net Capacity Resources	213,792	MW
Capacity Margin	16.0	%
Reserve Margin	19.0	%
With Uncommitted Resources		
Total Potential Resources	219,092	MW
Capacity Margin	18.0	%
Reserve Margin	22.0	%



*Reliability*First *Corporation (RFC), which began operation on January 1, 2006, was combined from portions of the former ECAR, MAAC, and MAIN regional reliability councils. Transition to a single set of processes and procedures is still in progress for all of the previous heritage regional activities, and is expected to be complete by the end of 2007. At this time, heritage regional requirements still apply to the former members now in RFC.*

All RFC members are affiliated with either MISO or PJM for operations and reliability coordination with the exception of Ohio Valley Electric Corporation (OVEC), a generation and transmission utility located in Kentucky and Ohio. OVEC is not affiliated with either RTO, but OVEC reliability coordinator services are performed by PJM.

Effective January 1, 2007, E.ON US and the City of Springfield, Illinois became members of the SERC region and are no longer a part of the RFC region. This assessment excludes E.ON US and the City of Springfield information and data for the entire summer 2007 season. All references to 2006 actual and forecast data are based on the current ReliabilityFirst regional boundaries, exclusive of these two entities.

Demand

Reliability*First*'s total internal demand forecast for summer 2007 is 183,400 MW. This is a demand forecast for the entire region that is derived from the demand forecasts of RFC member companies. Expected economic conditions account for the 2,200 MW (1.2%) increase in this year's forecast over the forecast of 181,200 MW for summer 2006. The load forecast each year is based on expected typical summer weather, or 50/50 weather. This means the actual weather on the peak summer day is expected to have a 50% likelihood of being hotter and a 50% likelihood of being cooler than the weather assumed in deriving the load forecast. In 2006, extreme weather resulted in a record peak demand of 190,800 MW served across the Reliability*First*

regional area. This is 9,600 MW (5.3%) higher than the total internal demand forecast of 181,200 MW for 2006, and 7,400 MW (4.0%) higher than the 2007 forecast. The weather service temperature and humidity indices on the peak day were for extreme heat across the entire Reliability*First* region. As an example of how extreme the weather conditions were, PJM reported that the conditions experienced last summer were a once in ninety seven years event for their RTO.

Many entities within the region have direct control load management programs and interruptible demand contracts that can be used by the system operators to curtail load, if needed. Some of these programs use radio control of water heaters and air conditioning; others rely on a signal or call to the customer to implement their load reduction. There are 3,800 MW of direct control load management and interruptible demand within the region that can be used to implement a planned load reduction should that be necessary to balance load and generation this summer. After accounting for the curtailment of direct control load management and interruptible demand, the peak net internal demand for the summer of 2007 is projected to be 179,600 MW.

Resource Assessment

RFC projects net capacity resources to serve demand in the region to be 213,792 MW (net seasonal capability), which is about 1,300 MW more committed capacity resources for the RFC regional area than there were in the summer of 2006. All of this capacity is considered "committed" capacity for this assessment, although there may be some capacity resources that do not satisfy the committed capacity requirements of the PJM and MISO markets. RFC projects its reserve margin (percentage of capacity resources that exceeds the net internal demand) based on these capacity resources to be 34,192 MW or 19.0% of the net internal demand. The forecast reserve margin in the RFC last summer was 20.1%. RFC has a reserve requirement criterion that will be implemented beginning in 2008. Until then, the RFC region is using a 15% reserve margin as a benchmark to compare to the projected reserve margin for this summer. The 19.0% reserve margin is expected to be adequate for this summer. A sensitivity calculation was made to determine the reserve margin under an extreme weather scenario. Adding 9,200 MW (5.0% of total internal demand) to the load forecast to account for extreme weather would reduce the projected reserve margin to 13.2%.

At this time, members have only reported arrangements to purchase 889 MW from outside the region. An additional 1,202 MW of member-owned capacity is located outside of the region, yielding a combined import of 2,091 MW. Members have also reported arrangements to sell 1,364 MW outside the region, for a total net import of 727 MW.

RFC has yet to conduct a comprehensive study of resource deliverability, having been in operation just over a year. The PJM RTO conducts analyses to determine that the aggregate PJM capacity can be delivered to the aggregate PJM load. PJM has listed approximately 5,300 MW of uncommitted and energy-only resources, which is not considered committed capacity in PJM. These resources may be deliverable under certain conditions, but for this assessment, RFC does not include these resources as deliverable for determining the reserve margins. MISO has developed a deliverability test consistent with its tariff which may or may not result in additional committed capacity within RFC, and which has not been included in this assessment.

Since only 3% of the regional capacity is hydroelectric, and more than half of the hydro capacity in RFC is pumped storage, there is no expectation that hydro conditions will be a regional concern.

Fuel

Although Reliability*First* monitors information on fuel supply and fuel delivery, the region does not explicitly consider fuel supply and fuel delivery interruptions in the resource adequacy assessment. Previous fuel supply or delivery problems were generally localized problems that were adequately addressed by the generation owner/operator. Also, the ReliabilityFirst region is broadly diversified with regard to the fuel supply, making it less susceptible to any one fuel supply problem. About 47% of the capacity uses coal for its fuel, with another 14% of the capacity being nuclear fueled. This 61% of the capacity is primarily base and intermediate duty generation. Oil and natural gas fuels 7% and 28% of the capacity respectively, and 3% of the capacity is hydroelectric. The remaining 1% of capacity uses a variety of renewable and other energy supplies.

A review of the information on natural gas in storage reveals that, at the middle of March, gas in storage is 18% above its 5 year average at this time of year according to the Energy Information Administration. Even with 28% (63,600 MW) of the regional capacity fueled by gas, ReliabilityFirst does not expect any problem with gas availability this summer. Also, a review of several major railroads has not uncovered any reported track conditions or railcar availability concerns that would be expected to cause significant coal delivery problems in the ReliabilityFirst region this summer.

Transmission Assessment

Historically, Reliability*First* and the heritage regions have experienced widely varying power flows due to transactions and prevailing weather conditions across the region. As a result, the transmission system could become constrained during peak periods because of unit unavailability and unplanned transmission outages concurrent with large power transactions. Generation re-dispatch has the potential to mitigate some of these potential constraints. Notwithstanding the benefits of this re-dispatch, should transmission constraint conditions occur, local operating procedures, as well as the NERC TLR procedure may be required to maintain adequate transmission system reliability.

Certain critical flowgates that have experienced TLRs in previous summers continue to be identified as heavily loaded in various reliability assessments and may require operator intervention to ensure adequate reliability levels are maintained. No major changes have been identified that would adversely impact reliability this summer.

New facility additions since last summer include the addition of a second 500/138 kV transformer at the Dominion Virginia Power (SERC) Dooms station increases transfer capabilities into the Mid-Atlantic area of Reliability*First*. The addition of a series reactor on the Dale-West Canton 138 kV line (FE-AEP tie) increases transfer capability into the northern Ohio and lower peninsula of Michigan areas. Over 500 MVAR of additional EHV and HV capacitors were installed in the Washington DC area since last summer, plus over 100 MVAR of distribution capacitors were also installed in that area.

The independent transmission project, Neptune HVDC, will go into commercial operation in June or July. The Neptune Regional Transmission System, LLC merchant transmission interconnection project consists of one HVDC connection from PJM to New York. The connection originates near the Sayreville 230 kV substation in PJM and will terminate at the Newbridge Road 138 kV substation on Long Island, New York. Capability will be 790 MW and the developer has requested firm transmission withdrawal rights in the amount of 685 MW and non-firm transmission withdrawal rights in the amount of 105 MW at the HVDC terminal in PJM.

Transmission constraints are an everyday occurrence in PJM and are handled seamlessly by dispatch methods. Units are normally dispatched in bid-price order. If a constraint occurs, out-of-bid-price-order-dispatch is instituted. Generators are then dispatched that do not further exacerbate the constraint. No transmission constraints are expected to cause a reliability concern for the upcoming season. All new generators wishing to be PJM capacity must pass load deliverability tests.

Reliability*First* actively participated in three Eastern Interconnection Reliability Assessment Group (ERAG) interregional seasonal transmission assessment efforts, and also conducts its own transfer capability analyses and assessment. Transfer capability results are included in each of the regional and interregional seasonal reports. Simultaneous import capabilities are projected to be adequate for the summer.

Operational Issues

The PJM portion of RFC has no significant reliance on any one fuel source, and does not depend on outside resources to any great extent. The MISO portion of RFC also has no significant reliance on any one fuel source.

In addition to the NERC TLR procedure, other operating procedures are available to maintain reliable system operations; such as a multiregional agreement involving balancing authorities around Lake Erie to use generation re-dispatch and phase angle regulator adjustments to mitigate emergency TLR procedures and curtailments in situations where the affected system(s) is about to curtail firm demand. Both MISO and PJM will need to continue to utilize a transmission constrained economic dispatch.

The Neptune line mentioned above will withdraw a significant amount of power from northern New Jersey. Contracts are in place with several generators in that area to supply the line. If a significant number of these generators trip off, the flow across the line into New York will be ramped down. In an extreme emergency, the flow on the line can be reversed to flow from Long Island to New Jersey.

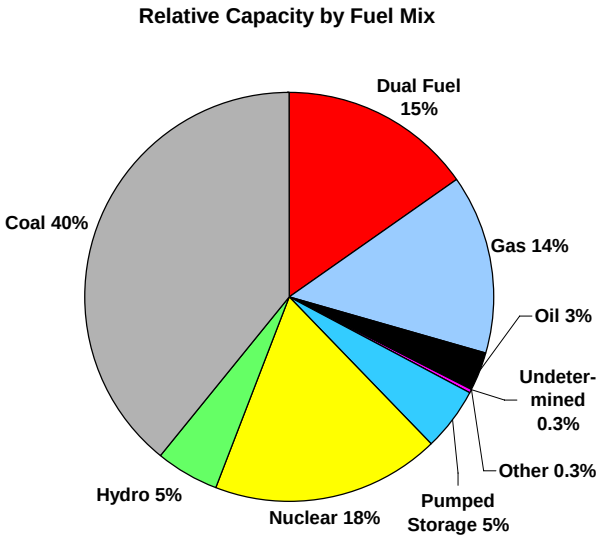
The output of the Potomac River generating plant in Washington, DC is still restricted because of environmental concerns. Potomac River may be dispatched during emergency conditions. In other areas, RFC does not expect local environmental restrictions on certain generating units to significantly impact availability during peak load conditions.
RFC does not anticipate any other major generating unit or transmission facility outages or any unusual operating conditions that could impact reliability this summer.

*Reliability*First *(RFC) membership currently consists of 46 regular members and 19 associate members operating within 12 NERC balancing authorities. RFC is a not-for-profit company incorporated in the State of Delaware whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. ReliabilityFirst was approved by the North American Electric Reliability Corporation (NERC) to become one of eight Regional Reliability Councils in North America and began operations on January 1, 2006.*

ReliabilityFirst is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council, the East Central Area Coordination Agreement, and the Mid-American Interconnected Network organizations. Additional details are available on the ReliabilityFirst Web site:
(http://www.rfirst.org)

SERC

Projected Total Internal Demand	200,655	MW
Interruptible Demand & DCLM	5,702	MW
Projected Net Internal Demand	194,953	MW
Last Summer's Peak Demand	199,945	MW
Change	0.4	%
All-Time Summer's Peak Demand	200,166	MW
Deliverable Internal Capacity	228,445	MW
Projected Purchases and Incoming Adjustments	3,564	MW
Projected Sales and Outgoing Adjustments	3,421	MW
Net Capacity Resources	228,588	MW
Capacity Margin	14.7	%
Reserve Margin	17.3	%
With Uncommitted Resources		
Total Potential Resources	265,043	MW
Capacity Margin	26.4	%
Reserve Margin	36.0	%



Demand

The SERC total internal demand for the 2007 summer is forecast to be 200,655 MW, which is 709 MW (0.4%) higher than the all-time peak of 199,945 MW that occurred in August 2006. The forecast 2007 summer peak (excluding new SERC members) is 192,410 MW which is 3,902 MW (2.1%) higher than the forecast 2006 summer peak of 188,508 MW. This projection is based on average historical summer weather. There were no significant changes in weather and economic assumptions since last year. However, small adjustments are continuously made to better match current economic and weather outlooks and to incorporate historical data into the analyses. The increase is due to typical load growth as well as the inclusion of the new entities in the region totals.

The SERC region has significant demand response programs. These programs allow demand to be reduced or curtailed when needed to maintain reliability. Traditional load management and interruptible programs such as air conditioning load control and large industrial interruptible services are common within the region. Interruptible demand and demand-side management capabilities for 2007 summer are 5,702 MW (including approximately 250 MW from new SERC members) as compared with the 5,044 MW reported last summer. A change in reporting philosophy regarding demand response programs resulted in the additional increase in interruptible demand and demand-side management. However, an offsetting change was made to the demand reported, resulting in no net change due to the change in reporting philosophy. In addition to the traditional demand response programs, the region's entities have various programs with monetary incentives to reduce demand during peak periods. Some examples are real time pricing programs and voluntary curtailment riders.

Temperatures that are higher or lower than normal and the degree to which interruptible demand and demand-side management is utilized can result in actual peak demands that vary

considerably from the reported forecast peak demand. Although SERC does not perform extreme weather or load sensitivity analyses at the region level to account for this, SERC members address these issues in a number of ways, considering all NERC, SERC, regulatory, and other requirements. These member methodologies must be documented and are subject to audit by SERC.

While member methodologies vary to account for differences in system characteristics, many commonalities exist. Common considerations include:

- Use of econometric linear regression models
- Relationship of historical annual peak demands to key variables such as weather, economic conditions, and demographics
- Variance of forecasts due to such things as high and low economic scenarios and mild and severe weather
- Development of a suite of forecasts to account for the variables mentioned above, and associated studies utilizing these forecasts.

In addition, many SERC members use sophisticated, industry accepted methodologies to evaluate load sensitivities in the development of load forecasts.

Regarding the influence of weather, the 90th percentile peak temperature relates to an extreme weather peak of about 6% higher than the regular forecast for the region. An extreme peak for 2007 summer equates to 206,649 MW of peak demand for the region. The capacity margin for this scenario is 8.8%, a reduced, yet adequate level for these conditions. This analysis assumes the load response to temperatures in this extreme range is linear. However, there is insufficient historical evidence to support this; at some point saturation occurs as temperatures rise into extreme levels. Therefore, the capacity margin could be even higher than the analysis indicates.

Planned firm sales across the SERC electrical borders total 1,921 MW and are comprised of 1,601 MW to FRCC, 203 MW to RFC, and 117 MW to SPP. These firm sales have been accounted for in the capacity margin calculations for the region.

Resource Assessment

Capacity resources in SERC are expected to be adequate to supply the projected firm summer demand. The projected 2007 summer capacity margin for SERC is 13.9%, which is lower than last year's projected capacity margin of 16.8%. This decline is primarily due to retail load in the Illinois service territory being served by the winners of the Illinois Auction process for the procurement of electricity or by individual power supply agreements. Some generators previously committed to serving Illinois load that did not get selected during the auction process are classified as uncommitted.

Environmental restrictions are not anticipated to significantly impact operations. No major generator outages are planned for the summer that could impact reliability. Hydro reservoirs are currently at normal levels as the incipient drought conditions in the Southeast experienced during last summer's season have improved. Current projections are for normal rainfall this summer. The reservoir levels are expected to be sufficient to meet forecast peak demands and daily energy

demands for the summer period. Several hydro facilities in the region are continuing to undergo major rehabilitation such as rewinding of generators, turbine replacements, switchyard work, and dam repairs. However, the outages are being coordinated in such a way that reliability and contractual commitments will not be impacted.

Planned firm purchases across the SERC electrical borders total 1,790 MW and are comprised of 978 MW from RFC and 812 MW from SPP. These firm purchases have been included in the capacity margin calculations for the region.

Although the SERC region does not maintain a regional reserve requirement, members adhere to their respective state commissions' regulations, and internal business practices regarding maintaining adequate resources. SERC members use various methodologies to ensure adequate resources are available and deliverable to the load.

SERC members expect over 2,600 MW of committed capacity and over 890 MW of uncommitted capacity to be placed in service by July 2007.

Deliverability is an important consideration in the analyses to ensure adequate resources are available at the time of peak. The transmission system has been planned, designed, and operated such that the region's generating resources with firm contracts to serve load are not constrained. Network customers may elect to receive energy from external resources by utilizing available transmission capacity. To the extent that firm capacity is obtained, the system is planned and operated in accordance with NERC Reliability Standards to meet projected customer demands and provide contracted transmission services. Therefore, SERC anticipates no constraints that would reduce the availability of committed capacity resources.

SERC members recognize that planning for variability in resource availability is necessary. Many SERC members manage this variability through reserve margins, demand side management programs, fuel inventories, diversified fuel mix and sources, and transfer capabilities. Some SERC members participate in Reserve Sharing Groups (RSG). In addition, emergency energy contracts are used within the region and with neighboring systems to enhance recoverability from unplanned outages. Measures such as emergency sales and purchases and activation of shared reserves have been used in the region during the past year. However, the frequency of their use has not increased relative to previous years.

Merchant Generation

SERC has had significant merchant generation development in the latter half of the 1990s and early 2000s. 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 the firm capacity margins reported for SERC. However, a significant amount of the uncommitted merchant capacity within the region has been participating in the short-term energy markets, indicating that a portion of the uncommitted resources is currently deliverable during certain system conditions.

To understand the extent of generation development in the region, it is instructive to examine the amount of generation connected to the transmission system for the upcoming summer's season.

Over 260,000 MW of generating capability is expected to be connected in the region. This generation exceeds the forecast summer total peak demand by over 60,000 MW.

Fuel

Sufficient inventories (including access to salt-dome natural gas storage), fuel-switching capabilities, alternate fuel delivery routes and suppliers, and emergency fuel delivery contracts are some of the important measures used by SERC members to reduce reliability risks due to fuel supply issues. SERC entities with large amounts of gas-fired generation connected to their systems have conducted electric-gas interdependency studies. In-depth studies have simulated pipeline outages for near- and long-term study periods as well as both summer and winter forecasted peak conditions. Also included, for each of the major pipelines serving the service territory, is an analysis of the expected sequence of events for the pipeline contingency, replacing the lost generation capacity, and assessment of electrical transmission system adequacy under the resulting conditions. Other SERC entities with less impact from gas generation are completing activities to map generators to their respective pipelines from which they are served. Dual fuel units are tested to ensure their availability and that back-up fuel supplies are adequately maintained and positioned for immediate availability. Some generating units have made provisions to switch between two separate natural gas pipeline systems, reducing the dependence on any single interstate pipeline system. Moreover, the diversity of generating resources serving load in the region further reduces the region's risk.

Current projections indicate that the fuel supply infrastructure and fuel inventories for the summer period are adequate even considering possible impacts due to weather extremes or other unexpected, extreme conditions. New international gas supplies are continuing to emerge for the U.S. market, positively impacting fuel inventories. While fuel deliverability problems are possible for limited periods of time due to weather extremes such as flooding, assessments indicate that this should not have a significant negative impact on reliability. The immediate impact will likely be economic as some production is shifted to other fuels. Secondary impacts could involve changes in emission levels and increased deliveries from alternate fuel suppliers.

Transmission Assessment

The SERC region has extensive transmission interconnections between its subregions. SERC also has extensive interconnections to the FRCC, MRO, RFC, and SPP regions of NERC. These interconnections permit the exchange of firm and non-firm power and allow systems to assist one another in the event of an emergency.

Approximately 134 miles of 161 kV, 230 kV, 345 kV, and 500 kV transmission lines and several station reliability improvement projects were completed from fall 2006 to spring 2007 with approximately 228 more miles of 161 kV, 230 kV, 345 kV, and 500 kV additions scheduled for completion prior to or during the 2007 summer season. SERC members invested approximately $1.21 billion in new transmission lines and system upgrades (includes transmission lines 100 kV and above and transmission substations with a low-side voltage of 100 kV and above) in 2006 and plan to invest approximately $1.53 billion in 2007 and $1.71 billion in 2008.

Coordinated interregional (ERAG) transmission reliability and transfer capability studies for the 2007 summer season were conducted among all the SERC subregions and with the neighboring

regions. These studies 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 reliability concerns or limits to transfers were identified.

Subregions

Entergy

In May 2005, Entergy submitted to FERC its filing to establish an Independent Coordinator of Transmission (ICT) pursuant to Section 205 of the Federal Power Act and Section 35 of the regulations of the FERC. Effective November 2006, the ICT was established and the Southwest Power Pool was approved as the ICT. The ICT has been certified as Entergy's Reliability Coordinator. In addition to this function, the ICT is also responsible for evaluating and granting transmission service requests, performing generation interconnection studies, administering Entergy's participant funding pricing protocol, facilitating a stakeholder process, performing the retrospective interconnection analysis, and developing the ICT Base Plan for the purpose of cost allocation.

Demand — The total internal demand for the 2007 summer season is forecast to be 27,730 MW based on normal weather conditions. This is 93 MW (0.3%) higher than the forecast 2006 summer peak demand of 27,637 MW and is 110 MW (0.4%) higher than the actual 2006 summer peak demand of 27,620 MW.

Resources — The projected capacity margin in the subregion is 13.9 % as compared to 21.2% last year. This decrease is primarily due to some generation previously reported as committed now being indicated as uncommitted (1,900 MW). New combined cycle and wind generation, totaling about 580 MW are expected online for 2007 summer to serve subregion load. The Entergy subregion has over 3,000 MW of firm purchases scheduled for 2007 summer. However, the resources are primarily from merchant generation located within the subregion with only about 700 MW of that coming from outside the subregion. Capacity in the subregion should be adequate to supply forecast demand.

Operational Issues — Entergy continues to monitor load shifts in the areas affected by Hurricanes Katrina and Rita. While the entire subregion expects to experience load growth in 2007, the growth rate in the New Orleans area is expected to be higher than in other areas as repopulation of the city continues post-Katrina. The areas just north of New Orleans as well as areas around Houston, TX and Jackson, MS are expected to continue to experience higher than average load growth within the subregion. Most loads affected primarily by Rita (i.e., outside of southeast Louisiana) have returned to pre-storm levels.

No reliability concerns are anticipated for the upcoming peak season as a result of the aftereffects of the 2005 hurricane season. No major generating unit outages or transmission facility outages which would impact system reliability are planned for the 2007 summer season.

Transmission — Several transmission projects to increase system reliability are scheduled for completion prior to or during summer 2007 in the Entergy subregion. A new 161 kV station will be built in northwest Arkansas to interconnect Entergy's and Southwest Power Administration's

(SWPA) facilities in the area. This connection will eliminate thermal overloads and low voltages which could potentially occur under contingency conditions. This project is expected to be in service by June 1, 2007. A second circuit from Entergy's Sterlington 500 kV station to the Perryville 500 kV station, both in north Louisiana, will be completed in May 2007. A second 500/230 kV autotransformer at Entergy's Ray Braswell station in Mississippi is in-service. These transmission system additions will complete an upgrade package to enable long-term service from the Perryville power plant as a network resource.

In total, 6 miles of 500 kV transmission and several station reliability improvement projects were completed for the 2007 summer season. Coordinated studies with neighboring regions and the other SERC subregions indicate that transmission transfer capability will be adequate on all interfaces this summer to support reliable operations.

Gateway

Expansion of the SERC membership in 2006 resulted in the creation of a fifth SERC subregion, the Gateway subregion. Effective January 1, 2007, the Gateway subregion further expanded to include new SERC members: City of Springfield, Illinois, and Dynegy.

Demand — The total internal demand for the 2007 summer season including the new members is forecast to be 18,984 MW based on normal weather conditions. This is 329 MW (1.7%) lower than the actual 2006 summer peak demand (including new SERC members) of 19,313 MW. The projected internal demand (excluding the new members) of 18,191 MW is 572 MW (3.2%) higher than the forecast 2006 summer peak demand of 17,619 MW. The increase in forecast load is due to normal load growth and the inclusion of the new membership in the subregion. The decrease from the 2006 actual peak is driven by hotter than normal temperatures during last summer's peak period.

Resources — The projected capacity margin in the Gateway subregion is 21.3% as compared to 33.6% last year. Beginning January 1, 2007 the retail load in the Illinois portion of the region began being served by the winners of the Illinois Auction process for the procurement of electricity or by individual power supply agreements. The generation resources to serve these retail loads are predominantly located within the Gateway subregion for this summer. The decline in the subregion capacity margin is primarily due to retail load in the Illinois service territory being served by the winners of the Illinois Auction process for the procurement of electricity or by individual power supply agreements. Some generators previously committed to serving Illinois load that did not get selected during the auction process are now indicated as uncommitted.

Operational Issues — No reliability problems are anticipated on the transmission systems of the Gateway subregion members for this summer.

However, a few transmission lines in the subregion can experience heavy loading during certain periods, particularly for heavy north to south flows during shoulder or off-peak conditions. For example, the 138 kV tie line between Ameren and the City of Springfield, Illinois and the Southern Illinois Power Cooperative's 161 kV tie line with Big Rivers Electric Cooperative have experienced heavy loading in the past and this condition may reoccur during the 2007 summer season. In the short term, constraints will be addressed through local operating procedures,

security-constrained economic (generation) redispatch, and the TLR process to maintain reliability.

Transmission — The addition of the Callaway – Franks 345 kV line from Ameren to AECI was completed and placed in service in December 2006. This line provides loading relief to the Bland – Franks 345 kV line, improves reliability in central Missouri, and ultimately, will serve as a supply to a new station in the area by summer 2008. This and other upgrades have resulted in more system flexibility and increased reliability for the subregion and its neighbors. In total, 54 miles of 345 kV transmission lines and several station reliability improvement projects were completed for the summer season. Coordinated studies with neighboring regions and the other SERC subregions indicate that transmission transfer capability will be adequate on all interfaces this summer to support reliable operations.

Southern

Demand — The total internal demand for the 2007 summer season is forecast to be 49,524 MW based on normal weather conditions. This is 1,657 MW (3.5%) higher than the forecast 2006 summer peak demand of 47,867 MW and 1,989 MW (4.2%) higher than the actual 2006 summer peak demand of 47,535 MW. The 2006 summer was slightly hotter than normal, but there was greater load diversity than expected. The increase in projected peak loads is due to normal load growth and an increase in the contribution of weather sensitive loads in the forecast.

Resources — The projected capacity margin in the Southern subregion is 13.5% compared to 14.8% last year. In addition to the resources included in the capacity margin calculation, demand side options are available during peak periods along with large amounts of merchant generation in the subregion. Capacity in the subregion should be adequate to supply forecast demand. Additionally, the preliminary results of the SERC Summer Reliability Study indicate assistance can be imported into the Southern subregion during the upcoming summer peak, if needed. Analysis for the most recent OASIS postings indicates simultaneous import capability to be over 5,900 MW for the most restrictive summer month. No local deliverability problems are anticipated.

McIntosh unit 1 (110 MW Compressed Air Energy Storage) experienced a forced outage during summer 2006. It is expected to be unavailable until March 2008. Two 48 MW Combustion Turbine units at Sowega were made operational in January 2007.

Operational Issues — No reliability problems are anticipated on the transmission systems of the Southern subregion members this summer. The Southern subregion routinely experiences significant loop flows due to transactions external to the subregion itself. These occurred last summer on the Southern-TVA and Southern-VACAR interfaces and this pattern is expected to continue for 2007.

The availability of large amounts of excess generation within the southeast results in fairly volatile day-to-day scheduling patterns. The transmission flows are often more dependent on the weather patterns, fuel costs or market conditions outside the Southern subregion than on loading within. Significant changes in gas pricing dramatically impact dispatch patterns. Adjustments to total transfer capability will be made as needed based on actual flows. Local procedures will be

utilized as needed, but no delivery problems are anticipated. Utilizing the TLR process is not anticipated, but available if necessary.

Transmission — Numerous 230 kV and 500 kV additions are scheduled for the Southern Subregion to serve load and address contingency loadings and voltages. A new interconnection between SMEPA and TVA is planned for operation on July 1, 2007 that will increase reliability in both the Southern and TVA subregions. An existing SMEPA – Entergy interconnection will be upgraded, doubling its capacity, for summer 2007 operation. In total, 55 miles of 230 kV and 500 kV transmission lines and several station reliability improvement projects were completed with approximately 58 more miles of 161 kV, 230 kV, and 500 kV additions scheduled for completion prior to or during the 2007 summer season.

TVA

Effective January 1, 2007, several new SERC members joined the TVA subregion: E.ON U.S. Services for LG&E and KU Companies, Owensboro, KY Municipal Utilities, and SUEZ Energy Marketing NA, Inc.

Demand — The projected total internal demand for the 2007 summer season including the new members is 43,146 MW based on normal weather conditions. The projected internal demand (excluding the new members) of 35,695 MW is 742 MW (2.1%) higher than the forecast 2006 summer peak demand of 34,953 MW. The projected total internal demand for 2007 is 1,170 MW (2.8%) higher than the actual 2006 summer peak (including new SERC members) of 41,976 MW. These increases are due to normal load growth and the inclusion of the new membership in the subregion.

Resources — The projected capacity margin in the subregion is 13.4% compared to 11.2% last summer. Capacity in the subregion should be adequate to supply forecast demand. The Gleason CT facility (three gas units, 520 MW total) and Marshall CT facility (eight gas units, 616 MW total) were recently acquired and placed in service. Subregion-wide, this will not significantly change the total available generation, but this previously undesignated generation is now committed to serving load in the subregion.

The Madison 2nd bank installation, required to be in service prior to the Browns Ferry Nuclear Unit 1 restart, was completed in March 2007. TVA is currently in the process of starting up Brown's Ferry Nuclear Unit 1 (1,065 MW) and it will be available to serve load for summer 2007.

Operational Issues — No reliability problems are anticipated on the transmission systems of the TVA subregion members this summer. The TVA transmission system has experienced large and volatile flows in recent years and these flows may occur again this summer. The 500 kV corridor in upper east Tennessee continues to experience congestion due to west to east and south to north transfer patterns. Additionally, the 500 kV corridor from western Kentucky to middle Tennessee can experience congestion during high west to east and north to south transfers. Big Rivers facilities continue to experience high loadings during certain generating unit outages, limiting the ability to import power into the BREC area. Operating guides have been developed to address these constraints this summer. A 345 kV interconnection is planned for construction to provide additional export capability. Other transmission improvements are

planned as well, including 17 miles of new 161 kV lines. However, these facilities will not be in service until after the summer peak season.

A lowering of the Wolf Creek dam water level to allow repairs over the next several years by the Corps of Engineers is not expected to impact overall system supply. An Operating Guide has been developed to address a rapidly developing scenario where this situation worsens.

EKPC is on schedule to have two new transmission facilities constructed and in-place by this summer that will eliminate constraints in eastern and central Kentucky. A new 138kV line from Cranston to Rowan County will reduce loading issues on the E.ON Goddard - Rodburn 138kV line in eastern Kentucky. A new 345kV line from JK Smith to North Clark (located in the Spurlock - Avon 345kV Line) will provide an additional path for power to flow through central Kentucky, thereby reducing the flows through EKPC's Avon 345-138kV substation, and also, possibly reducing the need to run combustion turbines at JK Smith.

Transmission — In total, approximately 98 miles of 161 kV transmission line additions and several station reliability improvement projects are scheduled for completion prior to or during the 2007 summer season. Coordinated studies with RFC members and the other SERC subregions indicate that transmission transfer capability will be adequate on all interfaces this summer to support reliable operations.

VACAR

Effective January 1, 2007, French Broad EMC became a new SERC member in the VACAR subregion.

Demand — The total internal demand for the 2007 summer season is forecast to be 62,331 MW based on normal weather conditions. This is 1,114 MW (1.8%) higher than the forecast 2006 summer peak demand of 61,217 MW and 1,391 MW (2.2%) lower than the actual 2006 summer peak demand of 63,722 MW, due to the hotter than normal weather last summer.

Resources — The projected capacity margin in the subregion is 13.1%, compared to 13.0% last summer. Capacity in the subregion should be adequate to supply forecast demand.

The Rockingham CT facility (825 MW) was purchased in November 2006. Subregion-wide, this will not significantly change the total available generation, but this previously undesignated generation is now committed to serving load in the subregion. Three CTs (90 MW) at Lee Steam Station were retired and two new CTs (84 MW) were commissioned in January 2007. Cross unit 3 (620 MW Coal) was declared ready for Commercial Operation in January 2007. In addition, the Anson CT facility is expected to be operational in June 2007 (six dual fuel units, 338 MW total). All are committed to serving load in the subregion.

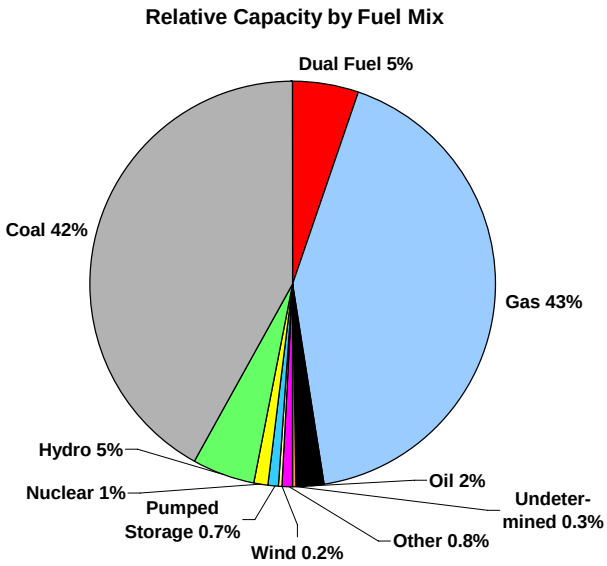
Operational Issues — No reliability problems are anticipated on the transmission systems of the VACAR subregion members this summer. Coordinated studies for the summer season were performed with RFC members and the other SERC subregions. These studies indicate that transmission transfer capability will be adequate on all interfaces this summer to support reliable operations. The Duke-to-TVA 161 kV tie will be removed from service from March until December 2007 for a line rebuild. No reliability problems are expected from this work.

Transmission **—** Several improvements to VACAR facilities have been completed or are planned. The new Darlington County – Florence 230 kV transmission line was energized in April 2006; the Camden-Dalzell 230 kV line was energized in June 2006; and the Kingstree-Cross 230 kV #2 line was energized in September 2006. These transmission lines are intended to reinforce delivery of power from the Cross Generating Station. Two additional 230 kV interconnections between Progress Energy-Carolinas and South Carolina are scheduled to be placed in service prior to the 2007 Summer Peak. A Static VAR Compensator (SVC) will be added in the northern North Carolina area of the subregion by June 2007 to reinforce voltages for certain load levels and unit outage combinations. The SVC will be connected at 100 kV and operate over a dynamic range of 100 MVAR reactive to 300 MVAR capacitive. Re-dispatch and load reductions can also be used to manage voltages in this area, if necessary. Numerous other additions, conversions, and projects to increase capacity were completed since the previous summer season. In total, 19 miles of 230 kV transmission lines and several station reliability improvement projects were completed with approximately 72 more miles of 230 kV and 500 kV additions scheduled for completion prior to or during the 2007 summer season.

The SERC Reliability Corporation (SERC) is a nonprofit corporation responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply systems in all or portions of 16 central and southeastern states. Owners, operators, and users of the bulk power system in these states cover an area of approximately 560,000 square miles and comprise what is known as the SERC Region. SERC serves as a regional entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the SERC Region. SERC is divided geographically into five diverse sub-regions (identified as Entergy, Gateway, Southern, TVA, and VACAR). Additional information can be found on the SERC Web site (www.serc1.org).

SPP

Projected Total Internal Demand	42,599	MW
Interruptible Demand & DCLM	761	MW
Projected Net Internal Demand	41,838	MW
Last Summer's Peak Demand	42,556	MW
Change	0.1	%
All-Time Summer's Peak Demand	42,284	MW
Deliverable Internal Capacity	45,039	MW
Projected Purchases and Incoming Adjustments	8,163	MW
Projected Sales and Outgoing Adjustments	3,650	MW
Net Capacity Resources	49,552	MW
Capacity Margin	15.6	%
Reserve Margin	18.4	%
With Uncommitted Resources		
Total Potential Resources	59,310	MW
Capacity Margin	29.5	%
Reserve Margin	41.8	%



Demand

The non-coincident internal demand forecast for the upcoming summer peak is 42,599 MW, which is 0.1% higher than the 2006 actual summer peak monthly total internal non-coincident demand of 42,556 MW. This demand was 2.8 % higher than the 2006 summer projection of 41,424 MW. Last year, SPP experienced a significant increase in demand due to abnormally high temperatures throughout the summer. SPP members, however, are not anticipating similar load demand this year.

Although actual demand is very dependent upon weather conditions and typically includes interruptible loads, forecasted net internal demands are based on expected typical summer weather, or 50/50 weather. This means the actual weather on the peak summer day is expected to have a 50% likelihood of being hotter and a 50% likelihood of being cooler than the weather assumed in deriving the load forecast. SPP does not anticipate 90/10 weather scenario this year.

These demand projections include the effects of interruptible demand and load management capabilities. The forecasted values are 746 MW of interruptible demand and 15 MW of load management. SPP is a summer peaking system and the winter peaks are normally substantially less than those experienced in the summer.

SPP has a total of 1,515 MW of long term firm sales to other regions for the summer season; they break down into 48 MW to ERCOT, 99MW to RFC, 1,003 MW to SERC, 0 MW to MRO and 365 MW to WECC. These long-term firm sales get reflected in the load flow models and may not necessarily match with the projected sales number in the summary table for SPP. The number in the summary table includes additional short-term firm sales from merchant generation, energy only resources, municipalities and other neighboring markets.

Resource Assessment

The SPP capacity margin based on committed resources is expected to be 15.6% for 2007 summer, which is slightly lower than the 2006 margin of 16%. This change is attributed to the increase in demand and very small increase in capacity for this summer. This, however, remains above the 12% minimum capacity margin criteria for the region. On an uncommitted resources basis, SPP has sustained around a 29% capacity margin.

Currently, SPP Criteria requires that members maintain a minimum capacity margin of 12%, unless their system is primarily hydro-based and then the capacity margin is 9%. This is adequate to cover a 90/10 weather scenario.

SPP has a total of 2,125 MW of projected purchases of which 2,020 MW are long-term firm and 105 MW are contingent firm. The long-term firm purchases from other regions for the summer season, are composed of 218 MW from ERCOT, 250 MW from RFC, 1,302 MW from SERC, and 250 MW from MRO. The 105 MW of contingent firm delivery service from WECC is administered under Southwestern Public Service Company's (SPS) tariff. These long-term firm purchases get reflected in the load flow models and may not necessarily match with the projected purchases number in the summary table for SPP. The number in the summary table includes additional short-term firm purchases as reported in EIA-411 for meeting capacity margin as well as all non-firm transactions from merchant generation, energy only resources, municipalities and other neighboring markets.

Fuel

All fuel supplies throughout the summer are expected to be adequate. SPP monitors potential fuel supply limitations for hydro and gas resources by consulting with its generation owning/controlling Members at the beginning of each year. Managing and predicting the energy output from intermittent resources like run-of-river hydro and wind farms are more challenging. Wind resources are not expected to provide a significant portion of the region's capacity during peak load conditions. Although dispatched to help cover high peak periods, hydro capacity represents a small fraction of the total resources in SPP. Regarding adequacy, the coal supply of the Powder River Basin (PRB) is not considered to be a high-risk issue by SPP members at this time. Natural gas sources are abundant in the SPP region and are not considered to be at high risk regarding supply adequacy or security.

Transmission Assessment

American Electric Power West (AEPW) has just completed reconductoring the Chamber Springs-Tontitown 161 kV transmission line, and will also have 8 miles of new 161 kV line between Siloam Springs and Chamber Springs energized by this summer both of which will improve reliability in the Northwest Arkansas area. In addition, AEPW completed in the fall of 2006, a new 20 miles of 138 kV transmission line between Pittsburg and Winnsboro in Northeast Texas. AEPW is also reconductoring the 138 kV transmission line between Northwest Texarkana and Alumax Tap.

In an effort to improve the reliability in the Southwest Missouri area, Empire District Electric (EMDE) is constructing a new 161 kV transmission line between the Reinmiller and Tipton Ford substations.

To improve reliability in the Hutchinson, Kansas area, Westar Energy (WERE) has rebuilt the 115 kV transmission line between Hutchinson and Circle. Also included in this effort is a rebuild of the 69 kV transmission line between Hesston and the Golden Plain Tap. To enhance reliability northwest of Kansas City, Kansas, WERE will also be constructing a new 115 kV transmission line between Stranger Creek and Thornton Street.

In addition to these major projects, SPP has also directed many other projects across the region to address local reliability and resource deliverability for the 2007 summer.

The transmission system within SPP is expected to perform reliably over the 2007 summer load season. No new constraints have been identified to affect reliability. SPP is aware of the line loadings on the 115 – 161 kV transmission lines along the Oklahoma and Arkansas border and, while monitoring these closely, is working with other regions to assess and maintain the reliability of the system in the near future..

Flow patterns should remain similar to previous summers' operating conditions since no significant generation has been added since the 2006 summer.

Although SPP is not aware of any significant deliverability problems due to transmission limitation at this time, we will continue to closely monitor the issue of deliverability.

SPP has historically determined import capabilities and limits on a regional basis through the MMS agreement (MAIN, MAPP/MRO, & SPP). These inter-regional responsibilities have transferred to ERAG (Eastern Interconnection Reliability Assessment Group) which creates models and performs studies of regional import and export capability. SPP is involved in the MRSWS (MRO-RFC-SERC WEST-SPP) study that will be finalized in May 2007 for the 2007 summer peak load operating conditions. The preliminary results of this study show exports out of SPP to have no significant constraints for this upcoming summer peak condition. Imports into SPP from the East and North is limited due to Danville to Magazine 161 kV line and Russellville East to Russellville South 161kV line in NW Arkansas respectively. These transmission elements have a higher loading in the base case used for this study due to the modified MISO dispatch and nature of the MMWG cases that are used. SPP will work through ERAG to discuss the mitigation plan (if needed) for this import. However, SPP does not believe this will cause any reliability concern for the upcoming summer.

Operational Issues

There are no scheduled maintenance outages of operational concern. SPP does not anticipate any environmental and/or regulatory restrictions that could potentially impact reliability. As a result of this, SPP operations personnel anticipate normal summer operations.

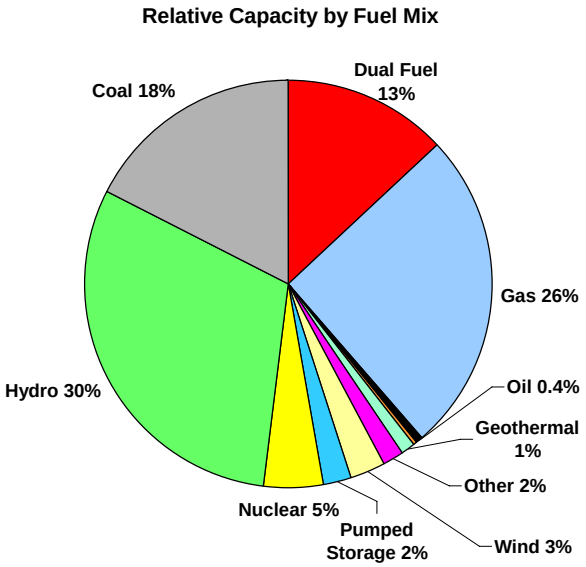
In February 2007, SPP launched its Energy Imbalance Services (EIS) Market when it began dispatching wholesale electricity. The wholesale energy market allows for more efficient deployment of generation across the SPP region through the establishment of an offer-based market for energy imbalance services. The EIS market will benefit consumers in our region by

creating an improved system for managing transmission and encouraging the most efficient use of resources.

Southwest Power Pool (SPP) region covers a geographic area of 255,000 square miles and has members in eight states: Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. SPP manages transmission in seven of those states. SPP's footprint includes 17 balancing authorities and 52,301 miles of transmission lines. SPP has 47 members that serve over 4.5 million customers. SPP's membership consists of 13 investor-owned utilities, 7 municipal systems, 10 generation and transmission cooperatives, 2 state authorities, 3 independent power producers, 11 power marketers, and 1 independent transmission company. Additional information can be found on the SPP Web site (www.spp.org).

WECC

Projected Total Internal Demand	157,075	MW
Interruptible Demand & DCLM	3,675	MW
Projected Net Internal Demand	153,400	MW
Last Summer's Peak Demand	160,501	MW
Change	(2.1)	%
All-Time Summer's Peak Demand	160,501	MW
Deliverable Internal Capacity	192,492	MW
Projected Purchases and Incoming Adjustments	612	MW
Projected Sales and Outgoing Adjustments	245	MW
Net Capacity Resources	192,859	MW
Capacity Margin	20.5	%
Reserve Margin	25.7	%
With Uncommitted Resources		
Total Potential Resources	192,988	MW
Capacity Margin	20.5	%
Reserve Margin	25.8	%



Demand

The aggregate WECC 2007 summer total internal demand is forecast to be 157,075 MW (U.S. systems 137,552 MW, Canadian systems 17,426 MW, and Mexican system 2,097 MW). The forecast is based on normal weather conditions and is 2.1 % below last summer's actual peak demand, which was established under generally above normal to well above normal temperatures in the region. The 2007 summer total internal demand forecast is 4.6% greater than the 2006 summer total internal demand forecast of 150,177 MW. Firm capacity commitments to external areas total 245 MW.

The internal demand forecast includes 506 MW of direct control demand-side management capability and 3,169 MW of interruptible demand capability. The 2007 direct control demand-side management capability and interruptible demand capability have increased by about 600 MW compared to last year. The direct control demand-side management capability is composed largely of air condition cycling programs. The interruptible demand capability includes industrial demand and water pumping demand.

Weather sensitivity analyses indicate that summer peak demands may increase by as much as 4,200 MW, assuming a one in ten year heat wave. Such a heat wave would reduce the region's capacity margin to about 18.4% and the reserve margin to about 23.1%.

Resource Assessment

For the peak summer month of July, WECC expects a capacity margin of 20.5%, which corresponds to a 25.7 % reserve margin. WECC's reserve margin last summer was 25.8 %. The forecast margin of approximately 25,000 MW only slightly exceeds this year's power supply assessment methodology planning margin of about 23,300 MW. Net committed capacity for this summer is expected to be 192,863 MW compared to 182,474 MW for summer 2006. The net

committed capacity resources of 192,863 MW include 612 MW of firm capacity purchases from external areas.

WECC has not established an interconnection-wide process to address the issue of planning for variability in resource availability due to fuel and other conditions. The hydroelectric resource capability used for this assessment has been reduced by roughly 5,000 MW to reflect river flow limitations and other factors. Installed wind capability has been reduced by about 6,000 MW to reflect expected available capability during the summer period. Transmission limitations that restrict generator access to the power grid are largely associated with wind farm interconnections. These limitations, however, do not exceed the wind derates referenced above. Transmission limitations for other generation sources are reported at 4 MW.

Fuel

WECC has not implemented a formal fuel supply interruption analysis methodology. Historically, coal-fired plants have been built at or near their fuel source and generally have long-term fuel contracts with the mine operators, or actually own the mines. Gas-fired plants were historically located near major load centers and relied on relatively abundant western gas supplies. Many of the older gas-fired generators in the region have backup fuel capability and normally carry an inventory of backup fuel, but WECC does not require verification of the operability of the backup fuel systems and does not track onsite backup fuel inventories. Most of the newer generators are strictly gas-fired plants, increasing the region's exposure to interruptions to that fuel source.

The Northwest expect near normal hydro conditions this summer. Colorado River runoff, however, may be below normal with little or no storage surplus to draw on to mitigate the reduced runoff. Year to date hydroelectric generation is below normal in California and that condition may continue throughout the summer period.

A survey of major power plant operators indicates that their natural gas supplies largely come from the San Juan and Permian Basins in western Texas, from gas fields in the Rocky Mountains, and from the Sedimentary Basin of western Canada.

It is not expected that extremes of summer weather during peak load conditions would have any impact on the fuel supply infrastructure. Dual-fuel capability is not a significant issue within the Western Interconnection. Only a nominal amount of generation outside of the Southwest has dual fuel capability and almost all of the Southwest dual-fueled plants are subject to severe air emission limitations that make alternate fuel use prohibitive for anything other than very short term emergency conditions.

Transmission Assessment

WECC and regional entities have several processes in place that relate to generation deliverability. For example, extensive operating studies are prepared that model the transmission system under a number of load and resource scenarios and operating procedures are developed to maintain safe and reliable operations. WECC prepares an annual power supply assessment that is designed to identify major load zones within the region that may experience load curtailments due to physically-constrained paths and internal resource limitations. Major power grid

operators have internal processes for identifying and addressing local area resource limitations, and independent grid operators have formal procedures for obtaining reliability must run capability, including voltage support capability, for resource-constrained areas. The resources reported in this assessment have been reduced to reflect deliverability constraints identified by transfer capability studies, interconnection agreement studies, etc.

The southern California area relies on significant amounts of imported power and it is expected that the transmission into that area of the Western Interconnection will be heavily loaded much of the time. The transmission system is considered adequate for all projected firm transactions but is expected to have a limited ability to support unusually large amounts of economy energy transfers. Reactive reserve margins are expected to be adequate for all expected peak load conditions in all areas. Close attention to maintaining appropriate voltage levels is expected to prevent voltage problems.

While WECC has eight back-to-back direct current ties to the Eastern Interconnection with a combined transfer capability of almost 1,500 MW, only about 400 MW of net capacity imports are planned for the 2007 summer period. The net non-simultaneous capacity imports for the 2006 summer were about 350 MW. It has been reported that the capacity imports have firm resource and associated firm transmission commitments.

Individual entities within the Western Interconnection have established generator interconnection requirements that include power flow and stability studies to identify adverse impacts from proposed projects. In addition, WECC has established a review procedure that is applied to larger generation and transmission projects that may impact the interconnected system. These processes identify potential deliverability issues that may result in actions such as the implementation of system protection schemes designed to ensure deliverability and to mitigate possible adverse power system conditions.

Operational Issues

WECC does not expect major generating unit outages, transmission facility outages, or unusual operating conditions that would adversely impact reliable operations this summer. No environmental or regulatory restrictions have been reported that are expected to adversely impact reliability. As a general practice, entities within the region prepare pre-season reactive studies for expected to above normal demand conditions. None of the pre-season study participants have reported expected voltage control issues for the 2007 summer operating period.

Other Items

The Northwest Power Pool and California Independent System Operator have publicly available documents on their respective websites that address 2007 summer conditions. Those documents are available at: http://www.nwpp.org/publications.html, (2007 summer has not been posted as of March 30, 2007) and at http://www.caiso.com/1b95/1b95abb649df4.pdf.

Subregions

California–Mexico Area

This is a summer-peaking area. The 2007 summer peak demand forecast of 58,925 MW is 7.3 % below last summer's actual peak demand of 63,572 MW. The areas' 2006 summer peak demand occurred during a period of unusually hot weather. The forecast peak demand includes 2,671 MW of interruptible demand and load management. The projected capacity margin for the peak month is 13.3%, excluding uncommitted resource additions of 185 MW.

The California ISO (CAISO) serves approximately 80% of the load in California. In its analysis of the probability of meeting various levels of operating reserve margins (ORM), the CAISO uses a historically based range of weather conditions to develop a range of summer peak demand forecasts[18]. The analysis combines this range of peak demand forecasts with a historical range of resource curtailments and transmission limitations. This analysis shows there is a 14% probability of having the ORM get to a level of 7% (utilizing demand response programs), a 4.6% probability of having the ORM get to a level of 5% (utilizing interruptible load programs), and a 2.9% probability of having the ORM get to a level of 3% (the point where firm load shedding may be initiated). For southern California (i.e., south of Path 26), the probabilities of reaching 7%, 5%, and 3% ORM are 18%, 4.7%, and 3.0%, respectively. For northern California, the probabilities of reaching 7%, 5%, and 3% ORM are 11%, 5.5%, and 3.5%, respectively. While the probability of using interruptible programs is much higher in southern California than in northern California, the probability of ultimately initiating firm load shedding is about the same for both areas due to the demand response and interruptible program amounts in southern California being approximately 80% greater than the amounts in northern California.

Although several major constrained transmission paths have been upgraded in recent years, path constraints still exist. In the summer of 2006 the Lugo-Serrano 500-kV Line Loop was put into service, which was supposed to increase the South of Lugo path limit from 5,100 MW to 5,600 MW. The 52 mile Otay Mesa 230-kV Power Loop project should be complete in the San Diego area by June of 2007. Operating procedures are in place to manage any high loading conditions that may occur during the summer. Entities within the area report having no concerns with maintaining adequate reactive reserve margins.

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. 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 area.

[18] http://www.caiso.com/1b95/1b95abb649df4.pdf?ht=2007%20assessment%202007%20assessment%202007%20assessment%202007%20assessment

Arizona-New Mexico-Southern Nevada Area

This is a summer-peaking area. The 2007 summer peak demand forecast of 30,086 MW is 0.1 % below above last summer's actual peak demand of 30,111 MW. Last summer's peak demand was higher than expected due to relatively hot temperatures. The forecast for the area includes 252 MW of load management and interruptible demand capability. The projected capacity margin for the peak month is 15.6 %.

Based on inter- and intra-area studies, the transmission system is considered adequate for projected firm transactions and a significant amount of economy electricity transfers. When 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. Some of the projects that are scheduled for completion prior to the summer season of 2007 are: The Centennial project in Nevada and the Gladstone – Walsenburg 230 kV line between New Mexico and Colorado. The Centennial project increases the transfer capability at Mead 230 kV, Harry Allen 230 kV, Navajo 500 kV and Eldorado Valley 500 kV Substations. The Gladstone – Walsenburg line is a new power path entailed building 117 miles of 230-kilovolt line from Walsenburg, Colo., to a new substation in Gladstone, N.M.

Fuel supplies are expected to be adequate to meet summer peak demand conditions. However, the area has experienced drought conditions and reduced water flows on the Colorado River and many other tributaries for a number of years. Last year's improved runoff conditions may not occur again this year and hydroelectric generation may be below normal.

Rocky Mountain Area

The Rocky Mountain Power Area's peak demand may occur in either summer or winter. The 2007 summer peak demand forecast of 11,546 MW is 4.6 % higher than last summer's actual peak demand of 11,038 MW. Last summer's peak demand was lower than expected due to a lack of widespread high temperatures. The forecast peak demand includes 204 MW of interruptible demand and load management capability. The projected capacity margin for the peak month is 14.6 %.

For the first part of the decade, water inflows into the hydro system were below average, resulting in below-average reservoir storage conditions. While inflows this past year or two have been much closer to normal, reservoir releases will be similar to last year and some purchases of energy may be required to supplement actual daily hydroelectric generation. 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 under normal hydro conditions the plant is 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. The Peetz Logan - Pawnee 230 kV

line is a 70 mile radial line and scheduled for completion in Q3 of 2007. This is being built to serve 400 MW of wind generation in Colorado.

Northwest Power Pool (NWPP) Area

The Northwest Power Pool 2006 coincidental summer peak of 54,597 MW occurred on July 24, 2006. The 2006 coincidental summer peak was 106% of the forecast; however, the coincidental peak occurred during above normal temperature conditions. Normalizing for temperature variance (50% probability), the 2006 coincidental peak would have been 51,597 MW or 100% of the forecast.

The 2007 summer peak forecast for the Power Pool area, as one single entity, of 53,000 MW is based on normal weather, reflects the prevailing economic climate, and has a 50% probability of not being exceeded. Extreme temperatures have the potential of increasing the coincidental peak by 3,500 MW. The Power Pool peak Area Load forecast includes approximately 550 MW of interruptible demand capability and load management.

Under normal weather conditions, the Power Pool area does not anticipate dependence on imports from external areas during summer peak demand periods.

Resources — Over 60% of the Power Pool resource capability is from hydro generation. In addition, generation is produced from conventional thermal plants and miscellaneous resources, such as non-utility owned gas-fired cogeneration or wind.

Hydro Capability — Northwest power planning is done by sub-area. Idaho, Nevada, Wyoming, Utah, British Columbia and Alberta individually optimize their resources to their demand. The Coordinated System (Oregon, Washington and western Montana) coordinates the operation of its hydro resources to serve its demand. The Coordinated System hydro operation is based on critical water planning assumptions (currently the 1936-1937 water years). Critical water in the Coordinated System equates to approximately 11,000 average megawatts of firm energy load carrying capability, when reservoirs start full. Under Average water year conditions, the additional non-firm energy available is approximately 3,000 average megawatts.

The 2007 mid-March forecast for the January through July Volume Runoff (Columbia River flows) at The Dalles, Oregon is 101 Million acre-feet, or 94% of the thirty year average.

Last year, the Coordinated System hydro reservoirs refilled to approximately 93.8% of the Energy Content Curve by July 31, 2006.

April through July — This period is the refill season when reservoirs store spring runoff. The water fueling associated with hydro powered resources can be difficult to manage because there are several competing purposes including but not limited to: current electric power generation, future (winter) electric power generation, flood control, biological opinion requirements resulting from the Endangered Species Act, as well as special river operations for recreation, irrigation, navigation, and the refilling of the reservoirs each year. Any time precipitation levels are below normal, balancing these interests becomes even more difficult. With the competition for the water, power operations for 2007 may be difficult. The goal is to manage all the competing requirements while refilling the reservoirs to the highest extent possible.

Sustainable Hydro Capability — Operators of the hydro facilities maximize the hydrology throughout the year while assuring all the competing purposes is evaluated. Although available capacity margin at time of peak can be calculated to be greater than 20%, this can be misleading. Since hydro can be limited due to conditions (either lack of water or imposed restrictions), the expected sustainable capacity must be determined before establishing a representative capacity margin. In other words, the firm energy load carrying capability (FELCC) is the amount of energy that the system may be called on to produce on a firm or guaranteed basis during actual operations. The FELCC is highly dependent upon the availability of water for hydro-electric generation.

The Power Pool has developed the expected sustainable capacity based on the aggregated information and estimates that the members have made with respect to their own hydro generation. Sustainable capacity is for periods at least greater than two-hours during daily peak periods assuming various conditions. This aggregated information yielded a reduction for sustained capability of approximately 7,000 MW. This reduction is more relative to the Northwest in the winter; however, under summer extreme low water conditions, it impacts summer conditions.

Thermal Generation — No thermal plant or fuel problems are anticipated. To the extent that existing thermal resources are not scheduled for maintenance, thermal and other resources should be available as needed during the summer peak.

Transmission — Constrained paths within the Power Pool area are known and operating studies modeling these constraints have been performed and operating procedures have been developed to assure safe and reliable operations.

The Northwest Operational Planning Study Group (NOPSG) coordinates seasonal inter-area transmission transfer capability studies. Daily studies to determine transfer capabilities during planned outage conditions are coordinated by the operators of the individual operating paths.

Transmission Facilities — No major transmission projects are scheduled for summer 2007. The Idaho to the Northwest Path (14) has recently undergone equipment changes on two of the three 230-kV lines in the path. The Ladd phase shifter failed on July 14, 2006, and has been removed from service. A 20-ohm switched reactor has been installed in the Lolo-Oxbow 230-kV line at Copperfield. This reactor is used to limit post-contingency loading on the Lolo-Oxbow 230-kV line. It is expected that summer studies will verify a west to east operating transfer capability of 1,090 MW, with a Midpoint-Summer Lake 500-kV line west to east operating transfer capability of 400 MW.

Operations — Control areas within the Power Pool use a fully automated system of sharing resources, when requested, to meet the NERC Disturbance Control Standard for loss of generation in the Pool area. The system has the ability to automatically move generation over a 2-Province, 7-State area while taking into consideration transmission constraints within the area. This system assures adequate resources are available over a broad area; an adequate response is delivered within the prescribed time; and the impact of the disturbance to internal as well as neighboring systems is mitigated.

During late 2000 and 2001 electricity demand decreased due to concerns surrounding the electricity crisis, large increase in electricity rates (retail and wholesale) and an economic slowdown. The Northwest Direct Service Industry (DSI), which is mostly aluminum smelters, experienced an electricity consumption drop from just above 2,500 average megawatts in 2000 to less than 500 average megawatts in 2002. It is anticipated that the electricity consumption for the DSI will be about 600 MW for the summer 2007 season.

The Northwest has developed an Adequacy Response Process whereby a team addresses the area's ability to avoid a power emergency by promoting regional coordination and communications. Essential pieces of that effort include timely analyses of the power situation and communication of that information to all parties including but not limited to utility officials, elected officials and the general public.

In the fall of 2000, the area developed an Emergency (ER) Response Process to address immediate power emergencies. The ER Team (ERT) remains in place and would be utilized in the event of an immediate emergency. The ERT would work with all parties in pursuing options to resolve the emergency including but not limited to load curtailment and or imports of additional power from other areas outside of the Power Pool.

In view of the present overall power conditions, including the forecasted water condition, the area represented by the Power Pool is estimating that it will be able to meet firm loads including the required reserve. Should any resources be lost to the area beyond the required forced outage reserve margin and or loads are greater than expected as a result of extreme weather, the Power Pool area may have to look to alternatives which may include emergency measures to meet obligations.

WECC's 182 members represent the entire spectrum of organizations with an interest in the bulk power system. Serving an area of nearly 1.8 million square miles and 71 million people, it is the largest and most diverse of the eight NERC regional reliability organizations. The WECC region is spread over a wide geographic area with significant distances between load and generation areas. In addition, the northern portion of the region is winter peaking while the southern portion of the region is summer peaking. Consequently, transmission constraints are a significant factor affecting economic grid operation in the region. However, reliability in WECC is best examined at a subregional level. Additional information can be found on the WECC Web site (www.wecc.biz).

Definitions and Abbreviations

How NERC Defines Bulk Power System Reliability

NERC defines the reliability of the interconnected bulk power system in terms of two basic and functional aspects:

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

Noteworthy Abbreviations Used in This Report

AZ-NM-SNV	Arizona-New Mexico-Southern Nevada Subregion of WECC
CA-MX	California-Mexico Power Area Subregion of WECC
DC	Direct Current
DSM	Demand-Side Management
ECAR	East Central Area Reliability Coordination Agreement
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
FCITC	First Contingency Incremental Transfer Capability
FRCC	Florida Reliability Coordinating Council
GWh	Gigawatt-hours
IESO	Independent Electric System Operator
IROL	Interconnection Reliability Operating Limit
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
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
MVA	Megavolt-ampere
Mvar	Megavolt-ampere Reactive
MRO	Midwest Reliability Organization
MW	Megawatts (millions of watts)
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NWPP	Northwest Power Pool Area Subregion of WECC
NYISO	New York Independent System Operator

RAS	Reliability Assessment Subcommittee
RMPA	Rocky Mountain Power Area Subregion of WECC
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool
SOL	System Operating Limit
TLR	Transmission Loading Relief
TVA	Tennessee Valley Authority
TWh	Terawatthours (trillions of watt hours)
VACAR	Virginia and Carolinas Subregion of SERC
VEM	VACAR-ECAR-MAAC
WECC	Western Electricity Coordinating Council

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