2006/2007 WINTER ASSESSMENT

The Reliability of the Bulk Power System in North America

North American Electric Reliability Council

November 2006

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INTRODUCTION

Mission of the Electric Reliability Organization

NERC's mission as the Electric Reliability Organization (ERO) 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 future adequacy; evaluates owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the ERO, NERC is subject to audit by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.

On July 20, 2006, the Federal Energy Regulatory Commission approved NERC's application to become the ERO for the United States. As the ERO, NERC will have legal authority 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 Commission'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." The *2006/2007 Winter Assessment* is the second assessment filed by NERC in its capacity as the ERO.

How This Assessment was Prepared

NERC, through the Reliability Assessment Subcommittee (RAS) of the NERC Planning Committee (PC), prepared this *2006/2007 Winter Assessment* based on data and information provided by the eight regional reliability organizations. While the report is based on these data and information and on summaries of regional self-assessments, its assessment summary represents NERC's independent judgment of the reliability and adequacy of the bulk power systems in North America for the upcoming winter peak demand period.

The assessment was prepared by conducting a peer review of the data and information submitted by the eight regional reliability organizations based on their member systems' projections for the 2006/2007 winter period. The subcommittee 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 winter; 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 subcommittee did not independently verify all of the information contained in the individual regional assessments, it did investigate and verify information where conflicting information was presented. Summaries of the supporting data are contained in the tables and figures throughout the report.

This assessment contains electricity supply and demand projections for December 2006 through February 2007 and is based on several assumptions:

- Normal peaking weather will occur.
- Economic activity will occur as assumed in the demand forecasts.
- Generating and transmission equipment will perform at average availability levels.
- Generating units that are undergoing planned outages will return to service as scheduled.
- Generating unit and transmission 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.
- Electricity transfers will occur as projected.

While the subcommittee prepares the overall seasonal assessment, it is the task of the individual regions to ensure that their members comply with NERC reliability requirements and have procedures in place to deal with conditions that might be outside the bounds of the assumptions underlying this report.

Key Findings

Peak Demands Projected to Grow; Capacity Margins Hold Steady

Peak demands are expected to be higher than those projected last winter in the U.S. and Canada. Available capacity margins show little change from last year's projections, with all regions and subregions projected to meet margin requirements. Even if extreme weather occurs, which can cause peak demands to exceed base forecasts by as much as 3 to 8% depending on regional load characteristics and weather patterns, available capacity margins will be adequate.

Transmission System Strengthened; Some Constraints Remain

Transmission systems have been reinforced in some areas, with notable improvements in the Boston and southwest Connecticut areas since our 2006 Summer Assessment. The TVA transmission system has experienced large and volatile flows in recent years due to large power transfers between areas to the north and south of the TVA system. These flows may occur again this winter. Critical flowgates in Reliability*First* that have also experienced heavy transmission loadings in previous winters continue to be identified as heavily loaded in various reliability assessments and may require operator intervention to ensure adequate reliability levels are maintained.

Hurricane Damaged Areas Are Stable and Recovering

Entergy continues to monitor load shifts in the areas affected by Hurricanes Katrina and Rita. NERC does not expect the after-effects of the hurricanes to reduce the reliability during the upcoming winter. Substantial reduction of load from previous winter forecasts is anticipated in the Gulf Coast area during a multi-year rebuilding cycle due to the widespread destruction of homes and businesses. In total, over 260 miles of 230-kV and 500-kV transmission line and several station reliability improvement projects were completed with approximately 50 more miles of 230 kV and 500 kV additions scheduled for completion prior to or during the 2006/2007 winter season.

Extreme Weather Remains a Threat to Reliability, but Should be Manageable

Extreme weather conditions during peak load periods should not materially affect the ability to supply electricity demand across the regions. The most likely impacts of extreme winter weather on fuel supplies are frozen coal and reduced natural gas availability due to high residential gas use. In areas with a high dependence on natural gas, the possibility of natural gas supply or transportation interruptions is always a concern during unexpected or extended periods of very cold weather when heating use of natural gas is high. Initiatives have been undertaken in New England, Florida, and Texas to increase coordination among natural gas suppliers and electric generators to proactively assess short-term fuel availability. Additionally, the Energy Information Administration reports that natural gas in storage at the end of August was the highest it has been in the last five years at that time of the year and 12% above the five-year average of gas in storage (see Web site at: http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html). In areas heavily dependent on coal-fired generation, generators "freeze treat" coal when weather conditions indicate the need.

Coal Deliveries Improve

Railroad track damage in late 2005 due to flooding and derailments limited delivery of coal from the Powder River Basin (north-central Wyoming and southeast Montana area) to a number of generating plants. As a result, NERC placed this issue on its reliability "Watch List" and has monitored developments. Service into and out of the Powder River Basin has improved significantly and coal stocks are increasing. As a result, NERC has removed this issue from its "Watch List."

Regional Highlights

ERCOT

ERCOT expects fuel supplies to be adequate this winter under normal conditions. However, there is always the possibility of widespread natural gas fuel supply interruptions during unexpected or extended periods of very cold weather when heating use of natural gas is high. Over 70% of ERCOT installed generating capacity is fueled by natural gas, and only one-fourth of that capacity has fuel switching capability and available alternative fuel inventory.

FRCC

FRCC has undertaken initiatives to increase coordination among natural gas suppliers and generators within the region to proactively assess short-term fuel availability. FRCC has also developed an independent and detailed natural gas pipeline model of the pipeline infrastructure within the region and has begun assessing vulnerabilities that are created as a result of the current natural gas delivery infrastructure.

MRO

MRO capacity margin is 25.2% and is judged adequate to maintain resource adequacy for the upcoming winter. MRO members do not expect to be directly impacted by the recent Powder River Basin coal delivery problems and expect to receive sufficient coal to allow generation at expected levels.

NPCC

All areas of the region expect sufficient resources to be available to meet projected demands during the 2006/2007 winter season. The New England gas supply situation should be improved by the approximately 1,700 MW of gas-fired generation that is expected to convert to dual-fuel capability in time for the 2006/2007 winter season. Also, ISO-NE is continually working to enhance the coordination between electric power system and natural gas system operations to improve reliability. Two new 345-kV cables have been added in the Boston area, and one new 345-kV circuit in southwest Connecticut that significantly improve system reliability in these areas.

RFC

Certain critical flowgates that have experienced heavy transmission loadings in previous winters continue to be identified as heavily loaded in various reliability assessments and may require operator intervention to ensure adequate reliability levels are maintained. A multiregional agreement involving balancing authorities around Lake Erie calls for the use of generation redispatch and phase angle regulators to mitigate curtailments in extreme system conditions.

SERC

Substantial reduction of load from previous winter forecasts is anticipated in the Gulf Coast area during a multi-year rebuilding cycle due to the widespread destruction of homes and businesses. In total, over 260 miles of 230-kV and 500-kV transmission line and several station reliability improvement projects were completed with approximately 50 more miles of 230 kV and 500 kV additions scheduled for completion prior to or during the 2006/2007 winter season. The TVA transmission system has experienced large and volatile flows in recent years due to large power transfers between areas to the north and south of the TVA system. These flows may occur again this winter. Operating guides have been developed to address these conditions should they reoccur.

SPP

SPP operations personnel anticipate normal winter operations. All fuel supplies throughout the winter are expected to be adequate, and there are no known unusual operating conditions expected to adversely affect reliability for the upcoming winter.

WECC

WECC anticipates that hydro conditions throughout the region will be sufficient to meet both seasonal peak demand and the daily demand this winter. 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. Consequently, the frequency and magnitude of schedule curtailments on constrained paths may increase compared with last winter.

Winter 2006/2007 Resources, Demands, and Margins[1]

Projected resources and margins shown in Tables 1a–c below do not reflect potential fuel supply problems or hydro limitations.

Table 1a: Estimated December 2006 Winter Resources, Demands, and Margins

December 2006	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	39,151	71,047	0	44.9	44.9
FRCC	37,327	48,540	1,190	23.1	24.9
MRO	32,684	45,739	45	28.5	28.6
NPCC	47,808	70,084	0	31.8	31.8
New England	21,497	32,342	0	33.5	33.5
New York	26,311	37,742	0	30.3	30.3
RFC	149,600	226,092	800	33.8	35.9
SERC	148,941	225,243	33,507	33.9	42.4
Entergy	19,529	35,567	16,602	45.1	62.6
Gateway	14,017	26,053	2,579	46.2	51.0
Southern	36,548	53,615	5,539	31.8	38.2
TVA	29,605	38,701	4,131	23.5	30.9
VACAR	49,242	71,307	4,656	30.9	35.2
SPP	29,411	47,055	8,082	37.5	46.7
WECC	105,608	153,581	0	31.2	31.2
AZ-NM-SNV	17,725	34,343	0	48.4	48.4
CA-MX US	39,783	51,069	0	22.1	22.1
NWPP	38,607	55,173	0	30.0	30.0
RMPA	9,493	12,996	0	27.0	27.0
Total-United States	**590,530**	**887,381**	**43,624**	**33.5**	**36.6**
Canada					
MRO	6,768	9,352	0	27.6	27.6
NPCC	61,690	75,596	0	18.4	18.4
Maritimes	5,190	6,610	0	21.5	21.5
Ontario	23,697	29,318	0	19.2	19.2
Quebec	32,803	39,668	0	17.3	17.3
WECC	20,959	22,688	0	7.6	7.6
Total-Canada	**89,417**	**107,636**	**0**	**16.9**	**16.9**
Mexico					
WECC CA-MX Mex	1,473	1,970	0	25.2	25.2
Total-NERC	**681,420**	**996,987**	**43,624**	**31.7**	**34.5**

[1] See notes to Tables 1a, 1b, and 1c on page 9.

Table 1b: Estimated January 2007 Winter Resources, Demands, and Margins

January 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	43,592	70,477	0	38.1	38.1
FRCC	44,792	53,431	1,190	16.2	18.0
MRO	31,466	45,668	45	31.1	31.2
NPCC	48,631	65,377	0	25.6	25.6
New England	22,320	27,891	0	20.0	20.0
New York	26,311	37,486	0	29.8	29.8
RFC	152,600	228,563	800	33.2	35.3
SERC	161,059	221,354	33,613	27.2	36.8
Entergy	21,174	35,332	16,602	40.1	59.2
Gateway	13,017	21,072	2,579	38.2	45.0
Southern	40,382	54,394	5,561	25.8	32.6
TVA	32,603	38,661	4,131	15.7	23.8
VACAR	53,883	71,895	4,740	25.1	29.7
SPP	28,519	47,055	8,082	39.4	48.3
WECC	104,504	151,074	0	30.8	30.8
AZ-NM-SNV	17,810	33,966	0	47.6	47.6
CA-MX US	37,970	48,907	0	22.4	22.4
NWPP	39,422	55,445	0	28.9	28.9
RMPA	9,302	12,756	0	27.1	27.1
Total-United States	**615,163**	**882,999**	**43,730**	**30.3**	**33.6**
Canada					
MRO	6,572	9,309	0	29.4	29.4
NPCC	64,859	75,543	0	14.1	14.1
Maritimes	5,508	6,590	0	16.4	16.4
Ontario	24,250	29,387	0	17.5	17.5
Quebec	35,101	39,566	0	11.3	11.3
WECC	20,603	22,605	0	8.9	8.9
Total-Canada	**92,034**	**107,457**	**0**	**14.4**	**14.4**
Mexico					
WECC CA-MX Mex	1,345	1,901	0	29.2	29.2
Total-NERC	**708,542**	**992,357**	**43,730**	**28.6**	**31.6**

Table 1c: Estimated February 2007 Winter Resources, Demands, and Margins

February 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	43,603	69,562	0	37.3	37.3
FRCC	36,918	51,630	1,190	28.5	30.1
MRO	32,746	45,668	45	28.3	28.4
NPCC	48,106	65,202	0	26.2	26.2
New England	21,795	28,085	0	22.4	22.4
New York	26,311	37,117	0	29.1	29.1
RFC	146,600	226,136	800	35.2	37.2
SERC	151,182	220,747	33,635	31.5	40.6
Entergy	18,965	35,350	16,602	46.4	63.5
Gateway	12,607	20,755	2,579	39.3	46.0
Southern	37,434	54,178	5,583	30.9	37.4
TVA	31,203	38,664	4,131	19.3	27.1
VACAR	50,973	71,800	4,740	29.0	33.4
SPP	29,744	47,055	8,082	36.8	46.1
WECC	101,867	145,538	0	30.0	30.0
AZ-NM-SNV	17,084	33,027	0	48.3	48.3
CA-MX US	37,533	44,885	0	16.4	16.4
NWPP	38,158	54,969	0	30.6	30.6
RMPA	9,092	12,657	0	28.2	28.2
Total-United States	**590,766**	**871,538**	**43,752**	**32.2**	**35.5**
Canada					
MRO	6,970	9,332	0	25.3	25.3
NPCC	62,447	74,610	0	16.3	16.3
Maritimes	5,564	6,428	0	13.4	13.4
Ontario	23,716	28,495	0	16.8	16.8
Quebec	33,167	39,687	0	16.4	16.4
WECC	19,853	22,520	0	11.8	11.8
Total-Canada	**89,270**	**106,462**	**0**	**16.1**	**16.1**
Mexico					
WECC CA-MX Mex	1,369	1,902	0	28.0	28.0
Total-NERC	**681,405**	**979,902**	**43,752**	**30.5**	**33.4**

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

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 — 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 — 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.

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

Capacity Fuel Mix

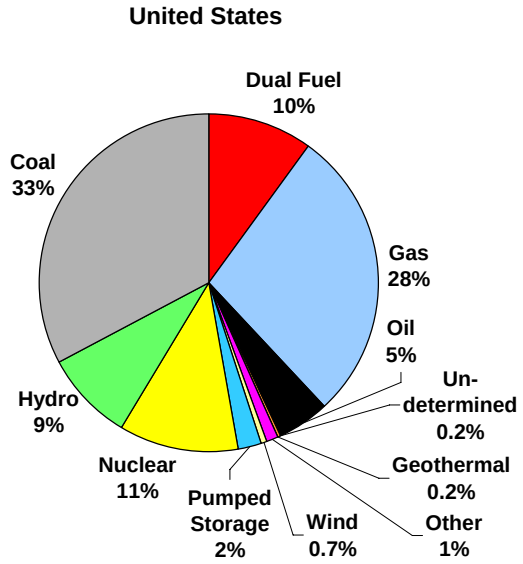


Figure 4a: U.S. Capacity Fuel Mix

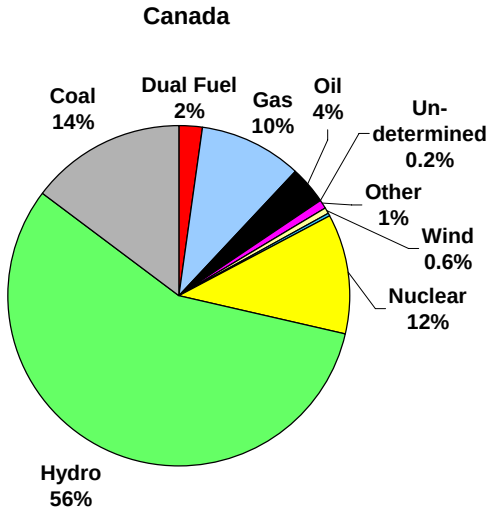


Figure 4b: Canadian Capacity Fuel Mix

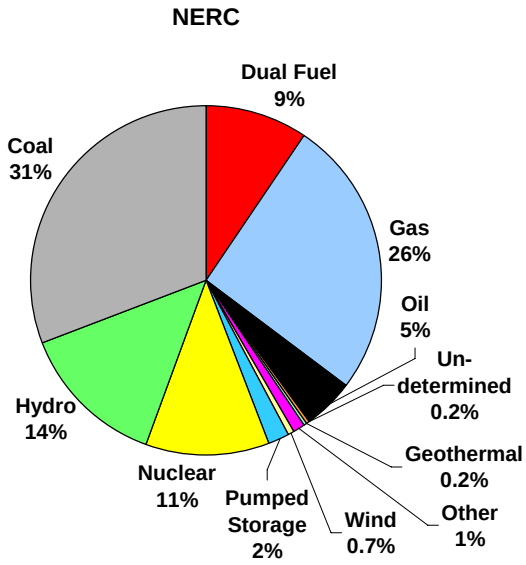
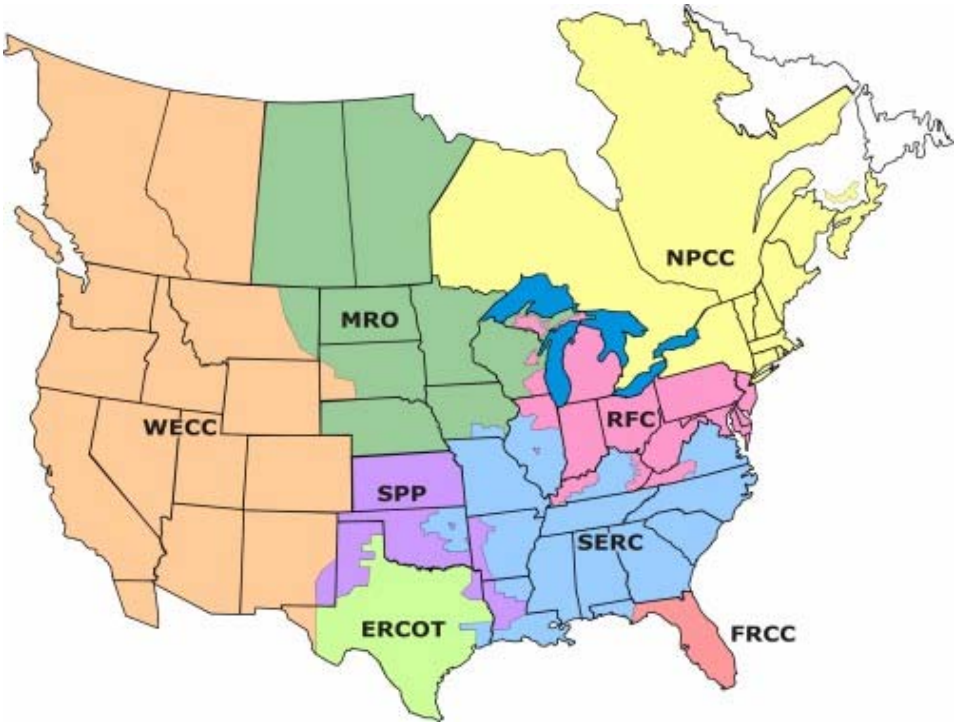


Figure 4c: NERC Capacity Fuel Mix

Figure 1: 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

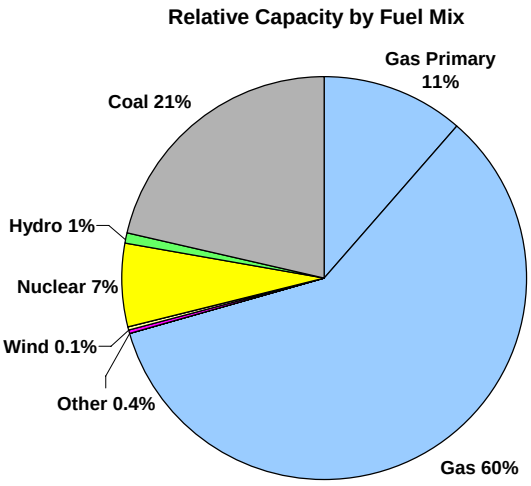
SERC
SERC Reliability Corporation

SPP
Southwest Power Pool, Inc.

WECC
Western Electricity Coordinating Council

Regional Self-Assessments
ERCOT

Projected Total Internal Demand	44,715	MW
Interruptible Demand & DSM	1,112	MW
Projected Net Internal Demand	43,603	MW
Last Winter's Peak Demand	48,064	MW
Change	(7.0)	%
All-Time Winter Peak Demand	48,064	MW
Deliverable Internal Capacity	68,519	MW
Projected Purchases	1,216	MW
Projected Sales	173	MW
Net Capacity Resources	69,562	MW
Capacity Margin	37.3	%
Reserve Margin	59.5	%
With Uncommitted Resources		
Total Potential Resources	69,562	MW
Capacity Margin	37.3	%
Reserve Margin	59.5	%



Demand

The Electric Reliability Council of Texas, Inc. (ERCOT) forecast peak demand for this winter is 44,715 MW, reflecting a 7% decrease from the winter 2005/2006 actual peak demand of 48,064 MW set on December 8, 2005 (all-time winter peak for ERCOT). ERCOT's demand and energy forecasts are made using econometric models, which utilize weather, population, and economic data among other factors. In completing these forecasts, ERCOT develops a baseline forecast and a reasonable range around this baseline due to uncertainty in forecast parameters. For winter 2006/2007, ERCOT is anticipating a return to seasonably normal (median) temperatures across Texas. In addition, ERCOT is reporting that a total of 1,112 MW of the forecast demand is interruptible.

Resource Assessment

Primarily due to economic reasons, generating entities in ERCOT have mothballed 9,188 MW of gas-fueled capacity for the 2006/2007 winter season. As a result of comprehensive reliability studies, ERCOT has executed Reliability Must-Run (RMR) contracts with 172 MW of capacity for local reliability needs that would have otherwise been mothballed. Even without the mothballed capacity and other unit retirements, the capacity margin in ERCOT is expected to be about 40% throughout the winter, well above the regional requirement of 11%.

Since last winter, wind generation in ERCOT has increased to 2,785 MW with most of this generation primarily located in west Texas. ERCOT assigns a 2.6% capacity factor to wind resources to account for the variability of wind during peak demand. The projected capacity margins for the 2006/2007 winter season are comparable to those of the last two winters, and no overall resource adequacy problems are expected. ERCOT notes a transfer of 173 MW to SPP due to SPP members' ownership of that amount of capacity of a power plant located in ERCOT. Entities in ERCOT have contracts that enable them to purchase about 1,200 MW from SPP if needed for emergency conditions; however, these purchases are not expected to be necessary to meet the demand requirements.

Fuels

ERCOT expects fuel supplies to be adequate this winter under normal conditions; however, a concern every winter in ERCOT is the possibility of widespread natural gas fuel supply interruptions. Historically these interruptions have occurred during unexpected or extended periods of very cold weather when residential heating use of natural gas is high, with the last significant interruption in ERCOT in winter 1983. Over 70% of ERCOT installed generating capacity is fueled by natural gas. Generation owners have identified that only one-fourth of that capacity has backup oil burning capability and available oil inventory. If any natural gas interruptions should occur and result in a reduction of available generation capacity to below required levels, ERCOT will initiate its Emergency Electric Curtailment Plan (EECP), which can be found in the ERCOT Protocols at: http://www.ercot.com/mktrules/protocols/current/05-050106.doc. ERCOT's EECP has been developed to maintain the reliability of the interconnection by avoiding uncontrolled load shedding.

Transmission Assessment

Local congestion issues may exist in the Rio Grande Valley and Laredo areas along the US border with Mexico, under high load conditions. As a result, ERCOT employs various congestion management processes to reliably control the flows across transmission constraints, including generation redispatch and other operating action plans.

Several new transmission improvement projects are expected to go in service this winter that will provide some congestion (summer loading) relief. The new Jacksboro to West Denton 345-kV line will improve west-east transfers, whereas, the Kendall-Cagnon 345-kV line will improve north-south transfers across ERCOT. There are several other additional projects currently under way to relieve transmission congestion, but they will not be completed this winter.

Any remaining transmission constraints are expected to be managed by ERCOT without affecting the reliability of the transmission system or reducing the availability of resources below required levels. Typically these constraints are not as severe in the winter months as in the summer season due to lower demand levels.

No interregional transmission transfer capability studies have been performed, since ERCOT is not expected to require external assistance to meet the projected winter peak.

Operational Issues

ERCOT expects no unusual operating conditions, or any environmental or regulatory restrictions during the winter that could cause operational problems.

Some generating units in or near load centers have scheduled planned annual maintenance during this winter. These outages have been studied and are not expected to impact reliable operations. One significant transmission outage will be the addition of the 345-kV Hillje substation at the interface of ERCOT's South to Houston Commercially Significant Constraint (CSC)[2]. This should help the import to Houston along this path. No other significant transmission outages have been planned for this winter.

ERCOT has a number of mitigation plans (MPs), remedial action plans (RAPs), or special protection systems (SPSs) in place to maximize transfers on the system while ensuring operations within reliability criteria. When activated due to certain system contingencies, these MPs, RAPs, and SPSs initiate manual

[2] Commercially Significant Constraints are the ERCOT equivalent of flowgates in the Eastern Interconnection and rated paths in WECC.

or automatic tripping, run-back of generators, or transmission line switching to maintain transmission security.

In addition, ERCOT does have plans for voltage reduction and interruption of firm load, if needed, to prevent uncontrolled loss of load. These steps are included in ERCOT's EECP and automatic under-frequency load-shedding requirements. In addition, a few localized areas have automatic under-voltage load shedding to prevent voltage collapse in their respective area.

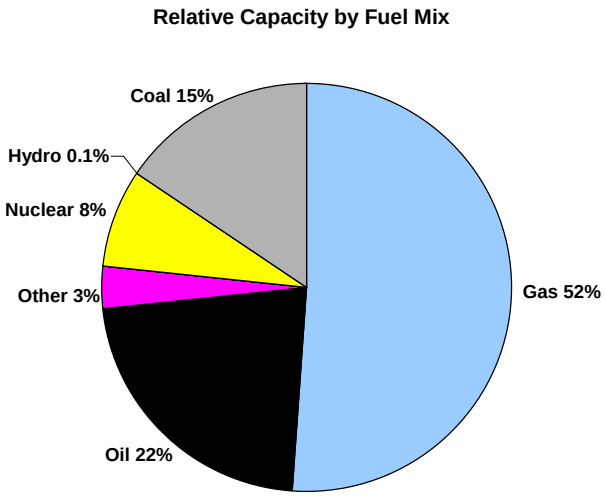
Assessment Process

Under Texas state law, ERCOT is the independent organization charged with nondiscriminatory coordination of market transactions, system-wide transmission planning, and ensuring the reliability and adequacy of the ERCOT electrical grid. In meeting these responsibilities, ERCOT has established and follows a set of Protocols and Operating Guides which can be found at: www.ercot.com.

ERCOT is a separate electric interconnection located entirely in the state of Texas and operated as a single balancing authority. ERCOT has 135 members that represent independent retail electric providers; generators and power marketers; investor-owned, municipal, and cooperative utilities; and retail consumers. It is a summer-peaking region responsible for about 85 percent of the electric load in Texas. ERCOT serves a population of more than 20 million in a geographic area of about 200,000 square miles. Additional information is available on the ERCOT Web site (www.ercot.com).

FRCC

Projected Total Internal Demand	48,296	MW
Interruptible Demand & DSM	3,504	MW
Projected Net Internal Demand	44,792	MW
Last Winter's Peak Demand	44,633	MW
Change	8.2	%
All-Time Winter Peak Demand	44,633	MW
Deliverable Internal Capacity	51,037	MW
Projected Purchases	2,394	MW
Projected Sales	0	MW
Net Capacity Resources	53,431	MW
Capacity Margin	16.2	%
Reserve Margin	19.3	%
With Uncommitted Resources		
Total Potential Resources	54,621	MW
Capacity Margin	18.0	%
Reserve Margin	21.9	%



Demand

The Florida Reliability Coordinating Council (FRCC) is forecast to reach its 2006/2007 winter peak demand of 48,296 MW in January, which represents a projected demand increase of 8.2% over the actual 2005/2006 winter peak demand of 44,633 MW, because of last winter's mild weather. This year's weather-normalized projection is consistent with historical FRCC demand growth, and is almost 3.4% higher than last year's forecast of 46,717 MW for the 2005/2006 winter peak demand. The peak demand forecast includes the potential 3,504 MW of demand reductions from the use of load management and interruptible load management programs.

Individual utilities within FRCC use either bandwidth analysis and/or Monte Carlo simulation to assess peak demand uncertainty and variability. For the bandwidth analysis, each company develops a bandwidth on the projected or most likely demand. The purpose of developing bandwidths on peak demand is to quantify all uncertainties of demand, which would include weather and non-weather demand variability such as demographics, economics, and the price of fuel and electricity. For the Monte Carlo method, simulations are performed on peak demands to arrive at a probabilistic distribution as to range and likelihood of this range of outcomes. Factors that determine the level of demand for electricity are assessed in terms of their own variability and this variability is incorporated in the simulations. If the installed and planned generation is sufficient to cover a significant portion of the demand variability, then the system is deemed to be reliable.

Resource Assessment

The net capacity resources available within the region to meet the projected winter peak yield a 21.9% reserve margin, exclusive of uncommitted resources, adequately satisfying the 15% reserve margin requirement. This year's forecast reserve margin is 3.7% lower than last year's margin of 25.6%.

Since the beginning of the year, net capacity additions of 600 MW will have been placed online prior to the upcoming winter season, with half of the generation resulting from newly commissioned gas-fired

generation, and the remainder from the uprate of existing facilities. No uncommitted generation has been reported for commercial operation prior to the upcoming winter season.

Currently, 1,552 MW are being imported into the region on a firm basis with another 842 MW dynamically dispatched out of the Southern subregion. These combined imports account for 5.3% of the reserve margin, and have firm transmission service to ensure deliverability into the FRCC region. FRCC has no firm long-term sales to other regions.

Only existing capacity that is under firm contract or committed to serve load has been included in FRCC's capacity resources. FRCC has 4,444 MW of existing merchant plant capacity, of which 3,254 MW are under firm contract and have been included in committed capacity resources. The committed resources are included in the various system operation conditions that are studied.

Fuel

The FRCC does not anticipate any fuel supply issues for the FRCC region during the projected peak winter demand period. There are no known fuel transportation issues affecting capability during peak periods and it is anticipated that fuel supplies will continue to be adequate for the winter operating season. During peak periods, operators typically minimize generation outages and rely on alternate fuel capabilities built into generation fleets to increase fuel diversity and minimize the effects of potential fuel supply disruptions. Use of specific fuel infrastructures is typically based on economic conditions surrounding the types of fuels, prevailing economics on the grid, and the availability of external purchased power. Typically, during peak winter conditions, operators may use some alternate fuel unit dispatch depending on system economics or fuel-supply infrastructure capabilities and design.

The FRCC regional load and resource plan is an assessment tool developed to aggregate regional capacity resource data from utilities within the FRCC. Included in the plan are requirements for specification and verification of primary and secondary fuel sources used for existing and planned generating facilities. The plan and the resulting data allows for regional fuel assessments regarding interdependency, diversity, and specific vulnerabilities. The plan, coupled with various operating procedures and detailed fuel data reporting protocols, provide the basis and starting point for limited quantitative assessments of fuel-supply interruption threats within the region.

Due to the growing interdependence of generating capacity and natural gas, the FRCC has undertaken initiatives to increase coordination among natural gas suppliers and generators within the region. This, along with fuel data reporting protocols and the field test of the Interim FRCC Short-Term Fuel Shortage Plan, provides the data necessary to proactively assess short-term fuel availability in order to provide operators with near-term health of the fuel delivery system along with the basis for other operational recommendations up to and including regional appeals for conservation.

In order to address the growing interdependence of generating capacity and natural gas on a long-term basis, the FRCC has developed an independent and detailed natural gas pipeline model of the pipeline infrastructure within the region and has begun assessing interdependency reliability impacts of pipelines and connected generation. The transient studies of pipeline performance, along with specific generation served and known fuel diversity, are being used to assess the effects of specific operational contingencies and will be used on an on going basis to independently perform reliability analyses and assess vulnerabilities that are created as a result of the current natural gas generation fuel delivery infrastructure.

Transmission Assessment

FRCC expects the bulk transmission system to perform adequately over various system operating conditions. The results of the *2006/2007 Winter Transmission Assessment*, which evaluated the steady-

state winter peak load conditions under different operating scenarios, indicates that any concerns about thermal overloads or voltage conditions can be managed successfully by operator intervention. Such interventions include generation redispatch, system sectionalizing, reactive device control, and transformer tap adjustments.

An interregional transfer study is performed annually to evaluate the transfer capability between FRCC and the Southern subregion of SERC. Joint studies of the Florida/Southern transmission interface indicate a winter seasonal import capability of 3,700 MW into the region, and export capability of 1,700 MW. Any transfer-related contingencies resulting in transmission overloads or voltage violations can be resolved by operating procedures.

Operational Issues

No scheduled maintenance outages of any significance are planned for the winter period. FRCC does not foresee any reliability issues for the 2006/2007 winter period, given no extreme weather conditions or unforeseen fuel supply issues.

Assessment Process

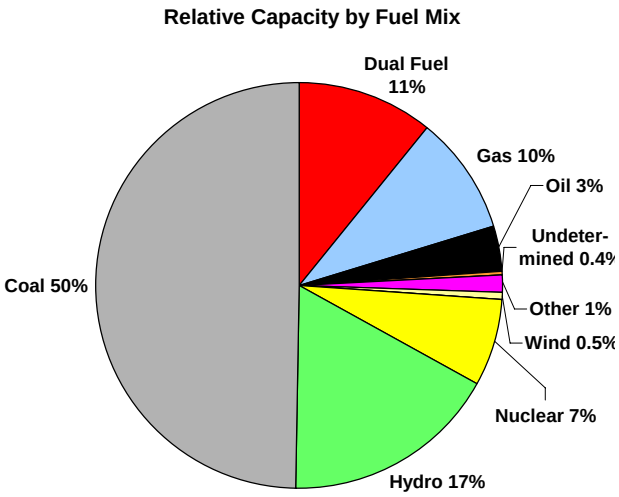
FRCC has a reliability coordinator agent that monitors real-time system conditions and evaluates near-term operating conditions of the bulk electric grid. The reliability coordinator uses a region-wide state estimator and contingency analysis program to evaluate current system conditions. These programs are provided with new input data from operating members every ten seconds. These tools enable the FRCC reliability coordinator to implement operational procedures such as generation redispatch, sectionalizing, planned load shedding, reactive device control, and transformer tap adjustments to successfully mitigate the line loading and voltage concerns that occur in real time, and those identified in the FRCC transmission studies.

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 109 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	40,877	MW
Interruptible Demand & DSM	1,161	MW
Projected Net Internal Demand	39,716	MW
Last Winter's Peak Demand	40,072	MW
Change	2.0	%
All-Time Winter Peak Demand	40,072	MW
Deliverable Internal Capacity	50,699	MW
Projected Purchases	2,796	MW
Projected Sales	373	MW
Net Capacity Resources	53,122	MW
Capacity Margin	25.2	%
Reserve Margin	33.8	%
With Uncommitted Resources		
Total Potential Resources	53,167	MW
Capacity Margin	25.3	%
Reserve Margin	33.9	%



In January 2006, several new members joined the Midwest Reliability Organization (MRO) who were previously members of the former Mid-America Interconnected network, Inc. (MAIN) region: Alliant, Madison Gas & Electric, Wisconsin Public Service, Wisconsin Public Power Inc., and Upper Peninsula Power Co. Because their data are included in this assessment, direct comparisons to last year's data would be incorrect.

Demand

The expected winter non-coincident total internal peak demand in combined MRO-U.S. and MRO-Canada is 40,877 MW. This forecast is 2.0% above last winter's actual peak demand of 40,072 MW, which includes the 2005/2006 actual data for the new MRO members. This year's winter demand forecast assumes average weather conditions. The total of interruptible demand and DSM programs available for the winter is 1,161 MW.

Both the Mid-Continent Area Power Pool (MAPP) generation reserve sharing pool (GRSP) and the former MAIN members group utilize a load forecast uncertainty factor when determining adequate generation reserve margin levels. The load forecast uncertainty considers both uncertainty attributable to weather conditions and economic conditions and is factored into the loss of load expectation study used to determine adequate reserve margin levels.

Resource Assessment

The projected MRO capacity margin is 25.2% and is judged adequate to maintain resource adequacy for the upcoming winter. This compares to the reported 2005/2006 winter capacity margin of 25.5%. The MRO, as a region, has not established a reserve requirement standard. In the MAPP GRSP, which does not include the new MRO members, resource adequacy is measured through the accreditation rules and procedures. The MAPP GRSP has a 15% reserve margin requirement and has determined that the GRSP members have 33.8% for the upcoming winter. The new MRO members, which are not part of the MAPP GRSP, continue to meet their former MAIN recommended reserve of 14% for the upcoming winter.

The capacity additions between October 1, 2006 and February 28, 2007 in the MRO system total 50 MW and consist of new internal combustion turbines, a number of wind sites, and uprates of existing units.

Net capacity imports into MRO are projected to be 2,423 MW. Purchases from outside the region are expected to be 1,538 MW, along with 1,258 MW of capacity that is owned but externally located for a total of 2,796 MW. Of the purchases, 1,449 MW are purchased from RFC members, 75 MW from SPP, and 14 MW from WECC. All 1,258 MW of the externally located generation is in the RFC region. Sales out of the MRO region are expected to be 373 MW, which consist of 127 MW to WECC, 71 MW to SPP, and 175 MW to RFC.

Fuel

Fuel limitations are not anticipated in the region for the winter of 2006/2007. MRO members do not expect to be directly impacted by the recent Powder River Basin coal delivery problems and expect to receive sufficient coal to allow generation at expected levels. If they find themselves falling short of required quantities of coal, their first course of action will be to back down generation at night and on the weekends as needed to ensure there is sufficient coal to allow them to operate at full output during peak hours.

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.

Environmental and regulatory restrictions are not expected to curtail availability of transmission during the winter.

The MRO-RFC-SPP *2006/2007 Winter Interregional Assessment* identified FCTTC limits between the three regions, which were found to be slightly lower than last winter's transfer capabilities. This is due mostly to the differences in the market dispatch in the 2006/2007 winter power flow model.

Transmission assessment issues for the individual MRO areas are reviewed below.

Iowa

Normal and reliable operation of the transmission system in the state of Iowa is expected during the winter of 2006/2007. Although there are a number of scheduled transmission and generation outages that will take place during this winter season, operational studies have shown that these outages will not cause any serious operational problems. Temporary operating guides will be provided, reviewed, and approved for those scheduled outages that may cause a potential violation of system operating limits. In addition, the new Council Bluffs – Grimes 345-kV line which was energized in the summer of 2006 is expected to have positive reliability impacts for the upcoming winter season. The Iowa Operating Review Working Group has reviewed winter transfer capabilities in preparation to the upcoming season. The standing operating guides for existing flowgates have been reviewed and will be in effect during winter 2006/2007. These standing operating guides contain a predefined sequence of control actions and mitigating steps, which will be implemented as necessary during the winter season. Iowa balancing authorities and transmission operators and MISO-St. Paul reliability coordinators will be closely monitoring Iowa flowgates and critical facilities. Midwest ISO binding procedures and NERC TLR will be used, in accordance with operating guides and regional congestion management procedures, to prevent violation

of system operating limits on all transmission facilities. Historically, winter operations in Iowa are characterized by significant south-to-north bias power transfers across the state of Iowa. Operationally, NERC TLR calls have proven to be effective to maintain the system within system operating limits. Temporary operating guides will be developed and issued whenever operational studies indicate a potential post-contingency overloading and/or need for TLR.

Nebraska

No significant operational concerns are expected in Nebraska during the winter of 2006/2007. Where large transfers might occur, operating guides and operating procedures have been put into place to maintain the reliable operation of the Nebraska regional transmission system.

Operational studies have been performed and will be updated as necessary for scheduled transmission and generation outages during the winter peak and off-peak time periods. Temporary operating guides will be issued for those outages that require actions or limitations to protect system operating limits.

Five constrained interfaces are posted on the MAPP OASIS, which are impacted by north-to-south and west-to-east transfers across the MRO system. Transfer limits on these constrained interfaces are not typical during the winter season in Nebraska. In the past, the Nebraska/Iowa regional transmission system has experienced heavy south-to-north transfers due to drought conditions and winter peak load conditions in northern MRO. These south-to-north transfers across the MRO system have a more profound impact on the eastern Nebraska system than on the western Nebraska system. A constrained interface is posted on the MAPP OASIS to address potential post-contingent overloads during heavy south-to-north transfers. All of these interfaces have approved operating guides that have proven effective in dealing with system conditions throughout the year.

Winter season load distributions are considered worst case for western Nebraska area stability. Operating guides have been developed that adequately protect the western Nebraska region for winter season load levels and maximum transfer conditions.

Northern MRO[3]

The transmission system in the Northern MRO region is expected to be completely in service for the beginning of the winter season. All former storm damaged lines are expected to be back in service. A normal amount of bulk transmission and concurrent generation outages are scheduled in the Northern MRO region for maintenance in late fall and early winter; however, no operating problems are expected. No significant new generation or transmission additions are planned to be in service prior to this winter season.

Operating guides are available to cover a range of water conditions in Manitoba. Reservoir levels throughout North Dakota, South Dakota, and Montana continue to be below normal. The conservation of these Missouri River reservoirs will likely reduce the level and duration of exports out of northwestern MRO and the region in general. The flow pattern in the Northern MRO area that was dominant during the recent winter seasons is expected to continue this winter season.

The existing standing operating guides in the Northern MRO have proven to be effective in dealing with the system conditions throughout the year. Temporary operating guides will be used as necessary for any unforeseen or weather-related occurrences.

[3] The term "Northern MRO" is used to designate the area that comprises Montana (MRO portion), North Dakota, South Dakota, and the two Canadian provinces of Manitoba and Saskatchewan.

Wisconsin–Upper Michigan

The transmission system for Wisconsin–Upper Michigan (WUM) is considered to be adequate for the upcoming winter season. The American Transmission Company's (ATCLLC) transmission system has been evaluated for system normal, N-1, N-2, critical breaker failure, and key multiple element contingencies according to NERC criteria. For the 2006/2007 winter season, the transmission system is expected to meet NERC standards for expected loads, generation, and firm transactions. All emerging thermal, voltage, or dynamic concerns at 100 kV and greater have budgeted reinforcements or operating guides to mitigate the violations.

The ATCLLC transmission system is susceptible to voltage instability during heavy imports into the region from the west (MAPP to WUMS). The default transfer limit of the Eau Claire – Arpin 345-kV line is defined as an Interconnection Reliability Operating Limit (IROL) and is closely monitored and managed by the Midwest ISO to no more than 790 MW. In addition, the Midwest ISO conducts a daily P-V analysis and establishes lower transfer limits when necessary to help prevent voltage instability.

The Gardner Park to Stone Lake 345-kV line is scheduled to be placed in service in November of 2006. A Temporary Operating Guide is being developed to help manage western interface loading with this new line in service to support construction outages outside the ATCLLC footprint. At this point in time, it is possible that the Eau Claire – Arpin IROL of 790 MW may be reduced during the winter pending final resolution of open items with study participants related to equipment ratings, pre- versus post-contingency actions and the potential deployment of a Special Protection Scheme at the Stone Lake substation.

Construction intended to improve the Flow South interface and increase transfer capability into the upper peninsula of Michigan from Wisconsin is scheduled to be completed in December. A standing operating guide will be issued to replace the existing temporary operating guide.

Reconductoring of the T-20 115-kV line between Rocky Run and Weston is scheduled to begin in late fall. During this construction outage, the Wausau area is more likely to reach the system operating limits (SOLs) for several N-2 outages involving Weston G3 and a 345-kV line.

ATCLLC is also participating in the Midwest ISO *2006/2007 Winter Assessment* studies that will be initiated shortly. The objectives of these studies are to provide system operators with guidance as to possible but acute system conditions that would warrant close observation to ensure system security.

Operational Issues

As a region, the MRO encompasses numerous operational seams: market-to-market (Midwest ISO to PJM); market-to-nonmarket (Midwest ISO to MAPP Regional Transmission Group); and market-to-Canadian province (Midwest ISO to Manitoba Hydro). 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.

The recent FERC filing made by the Midwest ISO for the seams operating agreement between Midwest ISO and MAPP has been addressing issues such as interim congestion management and redispatch and TLR procedures. As a result, MAPP and the Midwest ISO developed a software engine to implement congestion management on reciprocal coordinated flowgates. In addition, the Midwest ISO improved the ACE monitoring capability for its reliability authority and coordination with NERC IDCWG to hold intra-hour schedules to mitigate such events from happening in the future.

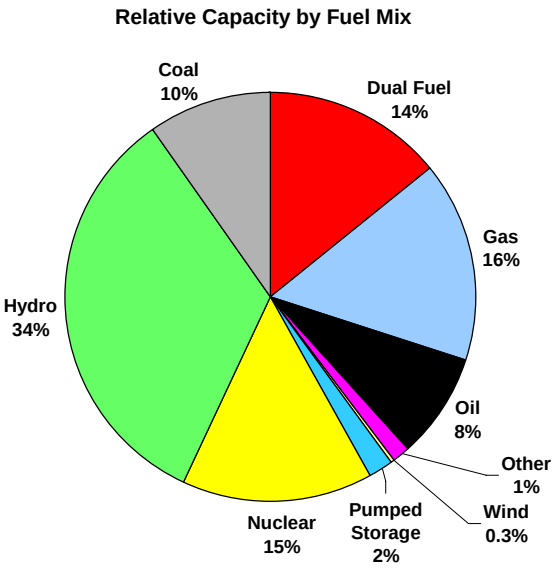
Assessment Process

The MRO Reliability Assessment Committee is responsible for this winter's reliability assessment. The committee relied on information provided by the MAPP Transmission Assessment Subcommittee, Transmission Operations Subcommittee, and Composite System Reliability Working Group to prepare the *MRO Winter Reliability Assessment*.

The MRO region includes more than 40 members supplying approximately 280 million MW hours to more than 20 million people. The MRO membership is comprised of municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations, and independent power producers. The MRO spans eight states and two Canadian provinces covering roughly one million square miles. Membership solicitation is ongoing. Additional information can be found on the MRO Web site (www.midwestreliability.org).

NPCC

Projected Total Internal Demand	115,437	MW
Interruptible Demand & DSM	1,947	MW
Projected Net Internal Demand	113,490	MW
Last Winter's Peak Demand	109,639	MW
Change	5.3	%
All-Time Winter Peak Demand	115,322	MW
Deliverable Internal Capacity	141,215	MW
Projected Purchases	981	MW
Projected Sales	1,276	MW
Net Capacity Resources	140,920	MW
Capacity Margin	19.5	%
Reserve Margin	24.2	%
With Uncommitted Resources		
Total Potential Resources	140,920	MW
Capacity Margin	19.5	%
Reserve Margin	24.2	%



The Northeast Power Coordinating Council (NPCC) includes five sub-regions (New England, New York, Québec, Ontario, and the Maritimes). The NPCC footprint geographically spreads over the northeastern part of the United States and the eastern part of Canada. It also spreads over part of the Eastern Interconnection and over the entire Québec Interconnection system, which is asynchronously connected to the Eastern Interconnection.

The total internal demand forecast for NPCC for the winter of 2006–2007 is 115,437 MW (Canadian systems: 66,576 MW; U.S. systems: 48,861 MW). Based on average weather conditions, this forecast is 0.9% higher than the total NPCC internal demand of 114,410 MW forecast for the winter of 2005–2006. When compared with the actual aggregate noncoincident demand of 109,639 MW experienced during the winter of 2005–2006, the increase is 5.3%.

All NPCC subregions (ISO-New England, 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 2006/2007 winter and have monthly projected net capacity margins ranging from 11.4% to 33.5%. Québec and the Maritimes are predominately winter-peaking areas and because of regional load distribution diversity with New York and New England, which are summer peaking, supply for external sales between areas is expected to be available, as necessary.

Generation additions within the NPCC subregions since last winter include more than 400 MW of new capacity in Ontario consisting of greater Toronto airport authority's 117 MW of combined-cycle generating plant and more than 300 MW of wind capacity from four wind farms. For the 2006/2007 winter, 70 MW of wind generation in the Maritimes, 113 MW of capacity uprates in New England, and 90 MW of wind generation in Ontario are anticipated. Currently, New England has 1.3 MW, the Maritimes have about 60 MW, and Ontario has 40 MW of wind resources counted toward winter internal capacity in this assessment.

Transmission additions for the 2006/2007 winter include: two new 345-kV cables from Stoughton to Hyde Park and K Street substations in the Boston area; the Plumtree-Norwalk 345-kV circuit in southwest Connecticut; a new 735/315-kV, 1,110-MVA transformer at the Arnaud 735/315/161-kV substation in Québec; two new 166-MVA transformers at Eastmain 1 in Québec; and a 345-Mvar 315-kV capacitor bank at the Hertel 735/315-kV substation in the Montreal area. These should all provide significant system reliability improvements.

A detailed summary of the expectations of each of the NPCC subregions follows.

Subregions

Maritimes

Demand — Based on the Maritime Area 2006/2007 demand forecast, a peak of 5,564 MW is predicted to occur in February. The forecast peak demand in January, which is the time of the NPCC forecast peak, is 5,508 MW. The actual peak for winter 2005/2006 was 4,863 MW on February 27, 2006, which was approximately 717 MW (12.8%) lower than last winter's forecast of 5,580 MW. This is due to higher than normal temperatures which resulted in a lower electric heating load than would normally be the case.

The area load is the mathematical sum of the forecasted weekly peak loads of the subareas (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 Maritime Area load included a coincidence factor, the forecast load would be approximately 1–3% lower. For the NBSO, the load forecast is based on an end-use model (sum of forecasted loads by use e.g., water heating, space heating, lighting) 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.

During the assessment period there is a 200 MW firm export with a New Brunswick point-of-receipt and a Québec (TransÉnergie) point-of-delivery.

Load management is not included in the resource adequacy assessment for the Maritime Area.

In the Maritime Area there is between 507 and 532 MW of interruptible demand available during the assessment period; there is 527 MW forecasted to be available at the time of the seasonal peak.

The Maritime Area does not develop an extreme weather forecast in its seasonal assessment.

Resource Assessment — The Maritime Area projected capacity margins for the assessment period range from 13.4% to 21.5%. The corresponding 2005/2006 winter Maritime Area capacity margin range was from 7.3% to 30.1%. About 70 MW of wind power generation is scheduled for addition to the Maritime Area during the winter period. 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 Maritime Area is projecting more than adequate

surplus operating margins above its operating reserve requirements for the winter 2006/2007 assessment period. These surplus margins range from 5% to 30% over the period from December 2006 through March 2007.

There are no firm purchases from other regions currently designated/scheduled to serve any loads in the Maritime Area during the assessment period.

There was no new capacity, committed or uncommitted, placed in service in the Maritime Area from March 1, 2006 to November 30, 2006.

The Maritime Area assesses its seasonal resource adequacy in accordance with NPCC C-13 Operational Planning Coordination procedure. As such, the assessment considers the regional operating reserve criteria; 100% of the largest single contingency and 50% of the second largest contingency.

The Maritime Area is forecasting normal hydro conditions for the winter 2006/2007 assessment period. The Maritime Area hydro resources are run of the river facilities with limited reservoir storage facilities. These facilities are primarily utilized as peaking units or providing operating reserve and do not have daily energy requirements.

The Maritime Area is not relying on outside assistance/external resources during the assessment period.

To ensure seasonal resource adequacy, the Maritime Area conducts an 18-month load and resource balance assessment in accordance with NPCC C-13 Operational Planning Coordination Procedure.

Fuel — The Maritime Area does not consider potential fuel-supply interruptions in the regional assessment. The fuel supply in the Maritime Area is very diverse and includes nuclear, natural gas, coal, oil (both light and residual), Orimulsion, hydro, tidal, municipal waste, and wood. Fuel supplies are expected to be adequate during the projected peak winter demand. Extreme weather conditions should have no impact on the fuel supply to the Maritime Area. Responsibility for fuel switching plans lies with the generation owner. All applicable units have the required procedures. The only units with fuel-switching capability are at Tuft's Cove, Nova Scotia (natural gas or oil) and Dalhousie, New Brunswick (Orimulsion or oil). Each facility maintains an adequate supply of its primary fuel.

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

Interregional transmission transfer capability studies are conducted seasonally.

Operational Issues — There are no major generating unit or transmission facility outages anticipated for the winter that will impact reliability in the Maritime Area.

There are no unusual operating conditions anticipated for the winter that will impact reliability in the Maritime Area.

There are no environmental or regulatory restrictions that could impact reliability in the Maritime Area.

New England

Demand — ISO-NE's balancing authority reference peak load forecast for the winter of 2006/2007 is 22,550 MW. This is 280 MW (1.2%) lower than the 2005/2006 winter projected peak of 22,830, and 230 MW (1.0%) lower than the weather normalized 2005/2006 winter peak load of 22,780 MW. The key

factor leading to the lower forecast is the expected response to higher electricity prices projected for 2006/2007. The electricity price increases (15% in 2005 and 20% in 2006) lower the New England net energy for load forecast (with an elasticity of -0.14), which in turn results in a lower winter peak forecast.

The reference case forecast is the 50/50 forecast (50% chance of being exceeded), corresponding to a New England weighted dry-bulb temperature of 6.8° F. The 6.8° F dry-bulb temperature corresponds to the 50th percentile of the extreme weather distribution and is consistent with the average temperature at the hour of the NEPOOL winter peak load for the previous 20 years.

For the winter period, there is a firm sale to New York (Long Island) of up to 345 MW via the Cross Sound Cable.

A total of 230 MW of demand resources that could be interrupted during times of capacity shortages is assumed available for the winter of 2006/2007. Not included in this assessment is voluntary load that will be interrupted based on the price of energy. As of September 1, 2006, there are approximately 167 MW enrolled in this program. 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 ISO-NE Operating Procedure No. 4 (OP 4), Action during a Capacity Deficiency. In general, these loads are available coincident with the system peak.

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 (50% chance of being exceeded), and extreme forecast (10% chance of being exceeded);
- economics — alternative forecasts are made using high and low economic scenarios.

The 2006/2007 winter load forecasts for the various weather and economic scenarios are:

Economic Assumptions	Weather Assumptions	
	50/50	90/10
Reference Economic Forecast	22,550 MW	23,475 MW
Alternative High Economic Forecast	22,850 MW	23,785 MW
Alternative Low Economic Forecast	22,265 MW	23,180 MW

ISO New England is concerned with meeting the extreme 90/10 peak demand based on the reference economic forecast.

A detailed regression analysis is made of the 1992–2005 heating season non-holiday weekday daily peaks. This analysis includes: the dry-bulb temperature at the time of the peak; the trend in each winter's daily peak sensitivity to dry-bulb temperature; and, the trend to each winter's daily peaks to energy. The forecasts are based on this analysis, household and income growth, 37 years of historical weather, and trends in the daily peak sensitivity to dry-bulb temperature. For more information on ISO-NE's load forecast, please refer to the ISO's Web site at: http://www.iso-ne.com/trans/celt/fsct_detail/index.html.

Resource Assessment — During the winter peak load period (January 2007), ISO-NE projects an installed capacity margin of over 5,500 MW (20.0%) for the reference case demand forecast and over 4,400 MW (16.7%) for the high case demand forecast. December and February available capacity

margins are greater than 5,100 MW for both the reference and high demand forecast. These projected margins are sufficient to cover the ISO 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 projected capacity margin in place during the 2005/2006 winter peak load period was about 11,200 MW. This is about 5,100 MW more than the 2006/2007 forecast margin. However, it should be noted that the forecast margin for 2006/2007 assumes that 5,000 MW of natural gas-fired generation will be unavailable, as explained in more detail below. Specific procedures are in place for 2006/2007 winter to minimize gas-generation unavailability; however, this conservative assumption was made to account for this possibility.

It is anticipated that ISO-NE will have sufficient capacity to meet the projected demand. If higher than anticipated unit outages are experienced, coupled with high electric demand, this will have an adverse effect on the capacity margins forecasted. Under the projected system, ISO-NE will meet its regional resource adequacy criterion of 0.1 day/year loss of load expectation (LOLE).

The forecast of monthly winter firm external capacity purchases is 451 MW. This includes 310 MW from Hydro-Québec, 50 MW from New Brunswick, and 91 MW from New York. Only firm purchases that are known in advance are included as capacity.

Since March 1, 2006, a total of about 113 MW has been added to the system in the form of generator uprates. In addition, a previously deactivated unit with a capacity of 20 MW has been placed back in service. An additional uprate of 23 MW is expected to become commercial prior to the winter period.

ISO-NE remains concerned about resource unavailability due to the regional lack of natural gas, which may result from the simultaneous need for natural gas by both electric generators and the core, space-heating market during the coldest winter days. To account for the possibility that many natural gas-only units may not be available at those times, the ISO includes an additional variable in its weekly operable capacity assessments during the highest winter load weeks of January and February: "generation at risk due to natural gas supply." For the 90/10 winter peak load case, that number is based on the total capacity of all gas-only units. Solutions to mitigate the potential for reduced availability of natural gas-fired units include: revised market rules and procedures (Appendix H of ISO-NE Market Rule 1) that coordinate electric and gas market timelines; continuation of the enhanced coordination between electric power system and natural gas system operations that began following the January 2004 cold snap; and implementation of additional conservation, energy-efficiency, and demand-response measures to reduce the system-wide dependency on gas-fired generating capacity.

In addition, as a result of the hurricanes of 2005, the ISO developed a new operating procedure, Operating Procedure No. 21, Actions during an Energy Emergency, to mitigate impacts resulting from all types of fuel-supply shortages or other abnormal system conditions. Although the original OP 21 procedures are no longer in effect, the ISO is developing an expanded OP 21 for implementation this winter.

The expected impact on operating reserves of significant resource unavailability is that OP 4, Action during a Capacity Deficiency, may have to be implemented to maintain system reliability and supplement operating reserves.

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

ISO-NE uses subarea probabilistic analyses to determine the impact of internal transmission constraints on resources. During the winter of 2006/2007, no transmission constraints that would affect the deliverability of generation are anticipated. In establishing the New England installed capacity requirement, 2,000 MW of external assistance was assumed to be available from the surrounding balancing authorities. This is in addition to the 451 MW of known firm purchases.

In the calculation of the capacity margin for the upcoming winter period, only firm purchases and sales are included as capacity. The 451 MW of purchases was assumed for the winter of 2006/2007, and 411 MW was assumed in 2005/2006. In addition to those contracts that are in place, there are ties with neighboring balancing authorities that can be used in times of emergency and on a daily basis based on economics. In terms of emergency capacity purchases during the winter period, ISO-NE will operate according to system rules and procedures to obtain the needed energy. For the ISO's winter operable capacity studies, we assume that 1,000 MW of emergency assistance is available from neighboring balancing authorities.

ISO-NE is conducting a tie reliability benefits study to identify the amount of emergency assistance that would be available from neighboring balancing authorities.

Fuel — ISO-NE considers the potential for fuel supply interruptions in its regional assessment by assuming additional unavailability of natural gas-fired generation. Under the reference (50/50) case, a total of 5,000 MW of gas-fired capacity is assumed unavailable. That value increases to 7,000 MW under the extreme (90/10) case. The assumed generation unavailability for the reference and extreme cases are based on the gas-only capacity that is expected to be interrupted at a temperature of 25° to 30°F and 0° to 20°F, respectively.

ISO-NE anticipates adequate fuel supply for the 2006/2007 winter season. However, there are concerns that during extreme cold days, natural gas-fired power plants will be competing with residential customers for gas. The ISO's primary concern is with those plants that lack firm transportation or supply contracts.

The New England region relies heavily on natural gas to generate electricity. Since New England's gas-fired electricity generators continue to compete with the ever-growing core natural gas market (i.e., for space heating) for supply and finite transportation infrastructure, fuel delivery issues could occur. The situation should be improved by the approximately 1,700 MW of gas-fired generation that is expected to convert to dual-fuel capability in time for the 2006/2007 winter season. Furthermore, ISO-NE is continually working to enhance the coordination between electric power system and natural gas system operations to improve reliability.

The operation of dual-fuel capability is verified by means of discussions with generator owners, as well as periodic fuel surveys.

Transmission Assessment — During the 2006/2007 winter, the following major transmission projects are expected to become commercial:

- Additional portions of the NSTAR 345-kV transmission reliability project consisting of two new 345-kV cables will emanate from Stoughton-one to the Hyde Park substation and one to the K Street substation and the Hyde Park autotransformer. These additions will continue to increase regional reliability by increasing transfer capability into the Boston load pocket.
- The Plumtree-Norwalk 345-kV circuit that will provide improved reliability to the southwest Connecticut area.

The 2006 Regional System Plan (RSP06), which will be published in fall 2006, discusses the transmission constraints that create deliverability problems in Western Maine, Massachusetts, and Connecticut. Resource adequacy studies show that the most critical area of New England is Connecticut. However, RSP06 does not identify any problems with meeting the 2006/2007 winter demands in any of the load pockets.

ISO New England's assumption regarding assistance available during the winter is lower than the expected interregional transfer capability.

Operational Issues — There are no major generator or transmission facility outages scheduled during the winter that are expected to impact reliability. No unusual operating conditions are expected. No environmental and/or regulatory restrictions are anticipated to impact reliability during the 2006/2007 winter period.

Assessment Process — ISO-NE uses a weekly operable capacity analysis to assess the reliability and adequacy of the region. The analysis takes into consideration the forecasted capability of all generators, net firm purchases and sales, the forecasted peak load exposure (both 50/50 and 90/10 forecasts), the operating reserve requirement, and planned and unplanned outages.

New York

Demand — The forecast peak for the NYISO is 26,311 MW, which is 961 MW higher than last year's forecast and 1,251 MW higher than last year's actual 2005/2006 NYISO peak load, which occurred on December 14, 2005. The actual peak for winter 2005/2006 was 25,060 MW, which was 290 MW (1.1%) less than last year's 25,350 MW forecast. The forecast load is 3.0% higher than the all-time winter peak load of 25,541 MW that occurred on December 20, 2004. The NYISO uses a weather index that relates dry-bulb air temperature and wind speed to the load response in the determination of the forecast. At the forecast load levels, a one-degree Fahrenheit decrease in this index will result in approximately 100 MW of additional load.

The NYISO Emergency Demand Response Program (EDRP) and Special Case Resources (SCR) load relief programs are only active during the summer capability period.

Resource Assessment — The New York projected capacity margins during the winter months are approximately 30%. The New York Area is summer peaking and winter season capacity availability is not a major concern, as indicated by the large margins.

The New York Area has projected Total Potential Resources of 37,486 MW in the peak winter month of January 2007 and a resulting Capacity Margin of approximately 30%.

Purchases of 80 MW from RFC and sales of 182 MW to RFC and 91 MW to New England are expected throughout the winter period.

Net resource additions, totaling 41 MW, are expected to be available for service during the winter period. The Maple Ridge phase 2 wind project, with a capacity of 100 MW, is expected to be available during the winter capability period, as well as the uprate of the existing Ginna station for an additional 95 MW. The overall capacity in the NY Area will be reduced by 154 MW due to the retirement of Huntley 65 and 66.

Transmission Assessment — No major transmission facility additions to the New York bulk power system are planned for the winter 2006/2007 period.

Fuel — Traditionally, the New York balancing authority generation mix has been dependent on fossil fuels for the largest portion of the installed capacity. Recent capacity additions or enhancements use natural gas as the primary fuel. Extreme weather or other conditions that might limit the availability of natural gas are not anticipated to impact system reliability in New York. A number of the steam units in southeastern New York have "dual-fuel" capability, employing the use of residual or distillate oil as an alternative to natural gas. Adequate supplies of all fuel types are expected to be available.

Transmission Deliverability — The NYISO uses a multi-area probabilistic model to evaluate the capacity requirements for the NY Area, and to assess the adequacy of projected resources to meet those requirements. The multi-area model includes transmission limitations between each of the modeled areas, including limitations both within New York and between New York and the neighboring systems, to ensure the deliverability of capacity resources to the load. The transmission limits included in the model are developed from power flow and stability studies that assess the emergency transfer limits between the areas with respect to NERC, NPCC, and local reliability standards and criteria. Dispatch-sensitive transfer limits are developed and represented in the multi-area model as necessary. Similar assessments are performed at the NPCC level with participation by PJM. The model and methodology used by the NYISO is consistent with that used by NPCC in the regional analysis.

Currently, the NYISO dispatches the system while optimizing loading across the voltage stability limited Central East interface. The Central East voltage limit is analyzed using comprehensive studies, and verified in real time for the actual configuration of the NYCA system. The NYISO regulates reactive power issues by implementing real power transfer limits on Central East, and bus voltage limits to protect against post-contingency voltage collapse.

Operational Issues — There are no major generator or transmission facility outages scheduled during the winter that are expected to impact reliability. No unusual operating conditions are expected. For the winter of 2006/2007, the NYISO has no reliance on outside assistance or external resources to meet reliability criteria. No environmental and/or regulatory restrictions are anticipated to impact reliability during the 2006/2007 winter period.

Assessment Process — NYISO has an extensive assessment process that reviews the reliability and adequacy of the New York system and ensures the deliverability of resources to load areas from internal New York and external sources.

Ontario

Demand — Ontario's forecast winter peak demand is 24,677 MW based on monthly normalized weather. The forecast peak for winter 2006/2007 is 3.8% higher than the 23,766 MW actual peak demand experienced last winter. The forecast is 1.8% higher than last winters' weather-corrected peak demand of 24,238 MW. The 23,766 MW actual peak was 2.1% less than the 2005/2006 winter 24,272 MW forecast. There are no firm sales projected for the 2006/2007 winter period.

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 winter peak of 24,677 MW, the LFU is 522 MW.

The interruptible demand amounts to approximately 740 MW of which 427 MW is included for seasonal capacity planning purposes.

Resource Assessment — The Ontario projected capacity margin for the 2006/2007 winter peak period is 17.5%, which is considered adequate to meet demand and energy requirements during the winter period. No firm purchases or sales are scheduled for the winter.

Since last winter, more than 400 MW of new capacity was made available to the Ontario power system including the Greater Toronto Airport Authority's 117 MW of combined-cycle generating plant and more than 300 MW of wind capacity from four wind farms. Another 90 MW of wind capacity is expected to be connected in the fall. Ten percent of the installed wind capacity is assumed to be available at the time of peak, which is about 9 MW.

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 winter 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 winter peak demand and no fuel delivery problems are anticipated for this winter.

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 sufficient so that more explicit analysis is considered only on an ad hoc basis. For the oil and gas-fired generation, there is significant dual-fuel capability. The total capacity of the oil and gas units is 5,103 MW and of this, 2,100 MW or 41%, has dual-fuel capability.

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. This group, comprising various stakeholders, is establishing communication protocols, cross-functional training, contingency analysis, and gas-electric day coordination in order to manage operational and reliability issues in both energy sectors.

Transmission Assessment — The Ontario transmission system is expected to be adequate to supply the coming winter's demand under the forecast conditions.

The Niagara transmission expansion project will add a new 230-kV double-circuit line between Allanburg Transmission Station, in the Niagara peninsula, and Middleport Transmission Station southwest of Hamilton. Hydro One has advised the IESO that the project, originally scheduled for June 2006, was delayed and will not be available before winter 2006/2007 due to unforeseen circumstances. Once in service it will increase the capability of the transmission system connecting the Niagara River generation at Queenston to the grid in the Hamilton area by about 800 MW. This enhancement will also permit increased imports from New York of at least 350 MW, and up to 800 MW depending on the load and generation dispatch in Ontario.

Phase angle regulators (PARs) are in service on the Michigan-Ontario interconnection, but 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, resulted in significant congestion of imports from the Michigan direction during the summer of 2005 and in past years. The IESO, the Midwest ISO, Hydro One, and International Transmission Company have agreed to temporarily bypass the phase angle regulators for normal operation until an agreement is reached to make full use of their regulating capability. This is expected to increase Ontario's transfer capability to and from Michigan by 400 MW this winter.

Full regulating capability on the Michigan interface, combined with increased import capability from the Niagara direction following completion of the Niagara transmission expansion project, will provide a significant increase in the combined import capability from New York and Michigan.

Operational Issues — In June 2006, the demand management of Ontario resources was increased with the implementation of the Emergency Load Reduction Program to supplement the Transitional Demand Reduction Program and Emergency Demand Reduction Programs that were already in existence. This program is modeled on similar programs implemented by other ISOs. The amount now available under this program is about 330 MW.

There are no unusual operating conditions, environmental, or regulatory restrictions that are expected to affect the capacity availability anticipated for this winter. 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 site at: http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp.

Québec

Demand — The 2006/2007 winter projected peak internal demand is 36,391 MW. The projected peak internal demand for the 2005/2006 winter period was 36,418 MW. No particular industrial load additions are expected in 2006/2007. Residential and commercial load growth is somewhat counterbalanced by the shutting down of certain industrial loads such as sawmills and paper mills, and by a certain number of load conservation measures that have been implemented by Hydro-Québec Distribution. The actual peak internal demand for the 2005/2006 winter period was 33,636 MW. This is 2,782 MW lower than the projection. The all-time record internal peak load was 36,268 MW, occurring on January 15, 2004.

The long-term load forecasting is done by modeling economic activity, population distribution and growth, residential, commercial and industrial activity, and is based on a 30-year analysis of average weather. The monthly internal peak forecast is done using typical weather conditions for each winter month. For example, the typical weather at the time of the winter peak is established to be a temperature of -24.4 °C (-12 °F) and a wind speed of 18 km/h (11 mph). The forecasts are then normalized for calendar date, day of the week, and time of day.

For 2006/2007 winter, the Québec subregion has firm sales commitments of 455 MW, comprised of 310 MW to New England and 145 MW to Cornwall, Ontario.

Hydro-Québec - Distribution can rely on 250 MW of load management in the form of automatic voltage reduction for the winter operating period.

The total interruptible demand in the Québec subregion amounts to 1,546 MW, which is derated to 1,040 MW to account for operational constraints.

The Québec subregion does not forecast load under extreme weather conditions but analyzes various scenarios. Climatic uncertainty is modeled by recreating each hour of the 30-year period from 1971 to 2000 under the current load forecast conditions. Moreover, each year of historic data is shifted up to ± 3 days to gain information on conditions that occurred during a weekend for example. Such an exercise generates a set of 210 different demand scenarios. The base case scenario is the average of those 210 scenarios. The subregion does produce a high demand scenario. The forecast economic parameters are increased but the same methodology that is used for the base case is reproduced for this high case scenario. For the first year of forecasting, the high case scenario is 2 to 3% higher than the base case scenario.

At typical temperature and wind conditions for peak load, a 1°C drop in temperature or a 5 km/h wind speed increase causes a load increase of 400 MW. Peak load usually occurs during the evening period (17h00 to 19h00). The differences between the morning and evening peaks can vary from 500 MW to 700 MW and are attributed to the increase in domestic load and the early use of lighting during the Eastern Standard Time Period. When forecasting the weekly load curves, three basic forecasts are generated: a 50%, a 25%, and a 10% chance of being exceeded for any given week. This provides a range of potential peak demands that the system may experience during the peak period. The load forecast variability is about 1,500 MW. Since there is a large proportion of electric heating load on the system, an episode of extreme weather could induce a large load increase. By analyzing extreme historical weather conditions that have occurred in the past 40 years, TransÉnergie has calculated that the load could reach 40,300 MW during the worst of these episodes. This is equivalent to approximately 110 % of the normal peak value.

Resource Assessment — In its 2005 Triennial Review of Resource Adequacy, Québec requires 3,431 MW of reserves to meet the NPCC reliability planning criterion. This represents 9.3% of the peak load. For the 2006/2007 winter peak, 4,465 MW of capacity margin is expected, which represents 12.7 % of the internal peak demand.

Last winter, the capacity margins were more than 5,700 MW during the entire operating period (17% of the peak load). Last winter's weather was mild and the heating demand was low compared to the forecast.

Hydro-Québec Production has a firm purchase of 200 MW from New Brunswick, which is backed by a firm contract.

Hydro-Québec Production expects to have an additional 404 MW of capacity placed in service between October 1, 2006 and February 28, 2007, with the first two units to be commissioned at the Eastmain 1 powerhouse accounting for 320 MW. An additional 109.5 MW of wind power will be available for Hydro-Québec Distribution. In this assessment for Québec, wind power is completely derated. Hydro-Québec is in the process of evaluating the capacity value of wind power generation under winter peak conditions. Moreover, the private producer TransCanada Energy has built and commissioned east of the Montréal area, a 547 MW natural gas combined cycle generating station in full service since September 2006. TransCanada Energy has a firm purchase contract for the natural gas.

Generation plants do not share common infrastructures other than the transmission grid. Therefore, no extreme contingencies are foreseeable other than a loss of transmission capacity. During the winter operating period, the day-ahead capacity margin requirement is twice the operating reserve to account for uncertainties on load forecast and on the availability of generating units. TransÉnergie assesses a number of extreme credible contingencies that might occur beyond the largest single contingency. This may be the loss of a transmission corridor. This may also be the permanent loss of a major transmission path; for example, three 735-kV lines from Churchill Falls resulting in the loss of 5,200 MW of generation. These conditions, among others, have been assessed using stability and load flow analysis, and the appropriate mitigating measures have been documented. In all these cases, the impact on operating reserves (4,465 MW of capacity margin) depends on the availability of internal and external resources to supplement the loss of generation or import due to the contingency.

The Québec reservoir levels are sufficient to meet both peak demand and the daily energy demand throughout the winter. To assess its energy reliability, Hydro-Québec has developed an energy criterion that states that sufficient resources should be available to go through sequences of two or four years of low inflows having a 2% probability of occurrence. Hydro-Québec must demonstrate three times a year to the Québec Energy Board its ability to meet this criterion.

To determine the deliverability of generation (both internal and external) to load Québec prepares Triennial and Interim Reviews, participates in Seasonal and Long-Term Multi-Area Probabilistic Reliability Assessments, and adheres to NPCC's deliverability definition. There are no deliverability concerns.

Hydro-Québec Distribution includes, when planning its resources, a potential of 500 MW from interconnection assistance for winter months. When needed, short-term calls for tenders are launched and transmission capacity is reserved for those purchases. Last winter, 750 MW of external resources were planned for and commercial contracts were signed for capacity and transmission. For this winter, 450 MW are required to meet the NPCC criterion. To ensure external resources are available and deliverable, NPCC evaluates periodically the potential for Interconnection Assistance Reliability Benefits for each balancing authority. Its last report shows a potential of between 2,000 and 2,700 MW for the Québec subregion.

Fuel — The Québec subregion does not consider potential fuel supply interruptions in the regional assessment. The reason for this is that non-hydraulic resources account only for a small portion of total resources. Plants using heating oil or jet fuel are refueled by boat or by truck and generally not during the winter season. Natural gas is used at a single cogeneration plant and is delivered under a firm purchase contract. At these plants, no fuel deliverability problems are anticipated this winter. None of these plants has dual-fuel capability.

Transmission Assessment — Québec system additions done during the last year (2005 to 2006) include:

- The series compensation on the three Manicouagan–Lévis 735-kV lines at the Bergeronnes substation was successfully commissioned for the 2005/2006 winter peak period. The compensation was increased from 20 to 34% on these lines.
- The Jacques-Cartier 345 Mvar, 315-kV capacitor bank was also put in service on time.
- In 2006, TransÉnergie commissioned the 315-kV double circuit line from Eastmain 1 Generating Station to Némiscau 735/315-kV substation, on the James Bay subsystem.
- One 1,650 MVA, 735/315-kV transformer was placed in service at Némiscau.

Québec system additions anticipated for 2006/2007 winter include:

- A new 735/315-kV, 1,110-MVA transformer is being added at the Arnaud 735/315/161-kV substation on the Churchill Falls – Manicouagan subsystem. This will help to secure the load at Arnaud, which has gone up from about 900 MW to about 1,300 MW in the last year.
- TransÉnergie is also adding a 345 Mvar 315-kV capacitor bank at the Hertel 735/315-kV substation on the south shore of Montréal to upgrade voltage support in the load area of the system.

There are no long-term internal transfer limitations that will impact reliability on the Québec system. No major outages are expected and no major maintenance is scheduled during the winter. Transmission margins for the peak period are adequate to carry the net internal demand plus the firm capacity sales. Moreover, enough transmission capability remains on the system to carry additional resources that would be called upon if load was greater than forecast.

The Québec Interconnection is asynchronously connected to the Eastern Interconnection and is fully compliant with NPCC operating and planning criteria. Intra-Québec transmission capability studies are conducted periodically. Inter-tie with the Eastern Interconnection transmission capability limits are established periodically by TransÉnergie and adjacent subregions and shared with other NPCC subregions.

Operational Issues — No major generating unit or transmission outages are anticipated by TransÉnergie for the winter 2006/2007 operating period. No unusual operating conditions are anticipated. In addition, no environmental and/or regulatory restrictions that could potentially impact reliability are expected.

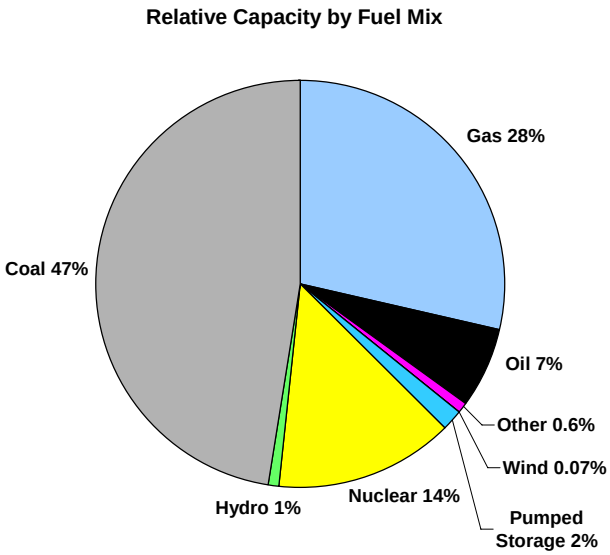
Assessment Process — Triennial and Interim Reviews and Seasonal and Long-Term Multi-Area Probabilistic Reliability Assessments are used to determine the reliability and adequacy of the Québec subregion.

NPCC is a voluntary nonprofit organization. Its 37 current members represent transmission providers and transmission customers serving the northeastern United States and central and eastern Canada. Also included are five nonvoting public interest memberships extended to regulatory agencies with jurisdiction over participants in the electricity market in northeastern North America as well as public-interest organizations expressing interest in the reliability of electric service in the region.

The geographic area covered by NPCC, approximately one million square miles, includes the state of New York, the six New England states, and the provinces of Ontario, Québec, New Brunswick, and Nova Scotia. The total population served is approximately 54 million. From an electric load perspective, 20 percent of the Eastern Interconnection load is served within NPCC. For Canadian electricity requirements, 70 percent of Canadian load is located within the NPCC region. Additional information can be found on the NPCC Web site (http://www.npcc.org/).

RFC

Projected Total Internal Demand	154,800	MW
Interruptible Demand & DSM	2,200	MW
Projected Net Internal Demand	152,600	MW
Last Winter's Peak Demand	149,816	MW
Change	3.3	%
All-Time Winter Peak Demand	149,816	MW
Deliverable Internal Capacity	226,683	MW
Projected Purchases	4,424	MW
Projected Sales	2,544	MW
Net Capacity Resources	228,563	MW
Capacity Margin	33.2	%
Reserve Margin	49.8	%
With Uncommitted Resources		
Total Potential Resources	235,863	MW
Capacity Margin	35.3	%
Reserve Margin	54.6	%



The former ECAR, MAAC, and MAIN regional reliability organizations have combined to form Reliability*First* Corporation (RFC), which began operation on January 1, 2006 as one of the now eight regional reliability organizations under NERC. Many of the former members of MAAC, most of the former ECAR members, and some of the former MAIN members are now members of RFC. Two former ECAR members have joined the SERC region, and the remaining former MAIN members have joined either the MRO or SERC regions. Transmission owners that belong to RFC, except for some in Kentucky and a small portion in Ohio, are members of either the MISO or PJM regional transmission organizations (RTOs). Transition to a single set of processes and procedures is still in progress for all of the previous heritage regional activities. 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 and E.ON US (a.k.a. LG&E Energy), a vertically integrated utility located primarily in Lexington and Louisville, Kentucky. OVEC is not affiliated with either RTO, but OVEC reliability coordinator services are performed by PJM. In addition, the Federal Energy Regulatory Commission (FERC) has approved the withdrawal of E.ON US from MISO effective September 1, 2006. At that time, Tennessee Valley Authority (TVA) became the reliability coordinator for E.ON US, which is now included in the TVA reliability plan. TVA is also included in the former ECAR regional reliability plan, which remains in effect.

Effective January 1, 2007, E.ON US will become a member of the SERC region and will no longer be a part of the RFC region. This assessment includes E.ON US information and data for the entire 2006/2007 winter season.

Demand

RFC's total internal demand forecast for winter 2006/2007 is 154,800 MW. This is 4,984 MW (3.3%) higher than the actual peak demand experienced by the RFC member utilities during the winter of

2005/2006. The regional demand forecast is derived by aggregating the demand forecasts of the utilities. The RFC member forecasts are based on expected average winter weather conditions and expected economic conditions during the winter of 2006/2007 based on late 2005 economic forecasts. The winter 2005/2006 demand forecasts are not available for comparison to the winter 2006/2007 forecasts. Demand-side management programs and interruptible demand contracts that could be utilized, if necessary, are expected to total 2,200 MW at the time of the winter peak.

At this time in the transition of ECAR, MAAC, and MAIN to Reliability*First*, this regional assessment does not specifically address peak demand uncertainty and variability, or the variability in demand due to weather. Planning for such uncertainties is the responsibility of each individual load serving entity. As a sensitivity analysis, a calculation based on a weather induced 5% load increase (7,700 MW) was performed. Even with such a load increase, the reserve margin would be adequate to meet the demand.

Resource Assessment

Generation projects are expected to add an additional 2,540 MW of capacity resources in the RFC region prior to the 2006/2007 winter peak. An additional 403 MW of capacity resources are expected to go in service during the winter season, for a total increase of 2,943 MW. These are all considered to be committed capacity resources for the purpose of this assessment.

RFC expects net capacity resources in the region to be 228,563 MW (net seasonal capability), which is about 3,500 MW more capacity resources for the RFC regional area than there were in the winter of 2005/2006. RFC forecasts its capacity margin to be 33.2%. The forecast capacity margin in the ECAR, MAAC, and MAIN regions last winter were 31.8%, 32.8%, and 39.6%, respectively. The reserve margin for this winter of 49.8% exceeds the MAAC reserve requirement of 15%, the MAIN recommended reserve of 14%, and the state of Wisconsin's requirement of 18%. ECAR did not have a specified reserve requirement.

RFC has developed a planning reserve requirement criterion, to become effective in the spring of 2008, for the 2008 summer peak season. Reliability*First* does not require individual members to plan for resource unavailability due to extreme credible contingencies that might occur. Therefore, RFC has not surveyed its members to determine how the individual members plan for resource unavailability beyond the largest single contingency.

At this time, members have made arrangements to purchase 3,389 MW and sell 2,544 MW outside the RFC region. An additional 1,035 MW of member-owned capacity is located outside of the region, for a minimum net expected import of 1,880 MW. None of these transactions are necessary for the members of the region to meet their respective reserve criterion.

Since the formation of RFC occurred only recently, a comprehensive study of resource deliverability has not yet been conducted. However, the PJM RTO conducts analyses to determine that the aggregate PJM capacity can be delivered to the aggregate PJM load. PJM has approximately 5,300 MW of uncommitted resources, which includes approximately 800 MW of uncommitted capacity and approximately 4,500 MW of energy-only capacity that is not considered committed capacity for this assessment.

A previous analysis conducted in ECAR had determined that about 2,000 MW of capacity might not be deliverable. That analysis determined the levels of export restriction from one area of the ECAR region to other areas in the region under first contingency conditions.

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.

The capacity and reserve margin data listed above includes the projected generator additions as committed capacity and excludes the undeliverable and energy-only generation from committed capacity. Based on the projected reserve levels, the committed capacity resources in the Reliability*First* region are expected to be adequate this winter.

Fuel

The Reliability*First* region has a diversified fuel supply. About 47% of the capacity uses coal for its fuel, with another 14% of the capacity being nuclear fueled. 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.

RFC does not perform an explicit fuel supply interruption study, but reviews the potential for major supply problems based on past disruptions reoccurring. Adequate pipeline capacity is expected to be available during the winter, when needed to operate the gas units. Although some 67,000 MW of the regional capacity is fueled by gas, high reserve margins will allow the expected gas usage to be minimized, if needed. Additionally, the Energy Information Administration reports that natural gas in storage at the end of August is the highest it has been in the last five years at this time of the year and 12% above the five-year average of gas in storage (see Web site at: http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html). RFC does not expect any problem with gas availability this winter.

At this time there are no known conditions affecting coal deliveries by rail that are expected to cause coal delivery problems for Reliability*First* members this winter. 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.

RFC expects each member to be ready to mitigate any fuel supply disruption that may occur. Although RFC has not compiled a list of mitigation actions that could be taken, some members may resort to fuel switching for those units with dual-fuel capability, if it becomes necessary to maintain reliable fuel supplies. Data available to RFC indicates that 13% (30,500 MW) of the regional capacity has dual-fuel capability. RFC has not verified with individual members the ease or difficulty involved with switching to alternate fuels.

The most likely impacts of extreme winter weather on fuel supplies are frozen coal and low gas availability due to high residential gas use. Coal is routinely treated to prevent freezing during winter when weather conditions indicate the need. Anticipated reserve margins should be sufficient to minimize the need for gas-fired electric generation. Extreme weather conditions during peak load conditions should not materially affect the ability to adequately supply generation across the region.

Transmission Assessment

Historically, 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 redispatch has the potential to mitigate some of these potential constraints. Notwithstanding the benefits of this redispatch, should transmission constraint conditions occur, local operating procedures, as well as the NERC transmission loading relief (TLR) procedure may be required to maintain adequate transmission system reliability.

Certain critical flowgates that have experienced TLRs in previous winters 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 system changes have been identified that would adversely impact reliability.

RFC actively participated in the existing interregional seasonal transmission assessment efforts. Transfer capability results are included in each of the interregional seasonal reports. Simultaneous import capabilities are projected to be adequate for the winter. A new interregional agreement, the Eastern Interconnection Reliability Assessment Group, has been executed between RFC and the five other regions in the Eastern Interconnection. This new agreement will become effective for the 2007 summer assessments.

Operational Issues

The PJM portion of RFC has no significant reliance on any one fuel source, and it doesn't depend on outside resources to any great extent. Furthermore, its membership's compliance with applicable criteria prevents any undeliverable load pockets. PJM is large enough that geographic diversity of weather helps balance its load factor and the load diversity is further enhanced by markets that are mature and well tested. External units that are considered capacity in PJM must sign an agreement specifying that if a capacity emergency is called, the capacity of the units must be provided to PJM. Transmission availability is secured before an external unit can be considered PJM capacity. The MISO portion of RFC also has no significant reliance on any one fuel source.

RFC does not anticipate any generating unit or transmission facility outages or any unusual operating conditions that could impact reliability this winter.

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 and phase angle regulator redispatch to mitigate emergency TLR procedures and curtailments in situations where the affected system(s) is about to curtail firm demand.

RFC does not expect local environmental restrictions on any generating units to significantly impact availability during peak load conditions.

Assessment Process

Within RFC, each individual company along with their RTO performs planning analyses for facility additions. Regional reliability assessments are performed to determine the adequacy of the existing and future bulk power system to serve projected load, given the proposed changes or additions to generation capacity and transmission facilities. The operating reliability impact of interactions with neighboring regions is assessed by participation in the MEN, MET, MMS, MSW, and VEM interregional groups.

RFC assessment procedures were applied to all generation and transmission facilities within the RFC footprint that might significantly impact bulk electric system reliability. These assessments consider RFC as a single integrated system. The generation resource assessment of the RFC systems on a region-wide basis has been performed for the upcoming winter peak demand season. The transmission assessment of the RFC systems on a region-wide basis has been performed for the first time for the upcoming winter peak demand season. If transmission deficiencies are discovered during this process, the member system with the deficiency will determine the actions to be taken.

The PJM RTO is planned and operated employing one security-constrained economic dispatch protocol using the applicable criteria of the respective region, local criteria, the PJM deliverability requirements, and PJM market rules. Through the operation and planning of the total PJM footprint, reliability is ensured.

The PJM market rules include a capacity market and the use of a locational marginal pricing mechanism to make congestion transparent. Making congestion transparent through locational marginal pricing provides a market mechanism to allow for mitigation of congestion.

The MISO market rules also include the use of a locational marginal pricing mechanism to make congestion transparent. The MISO energy market tariff requires load serving entities to comply with their applicable resource adequacy standards. Load and capability information is reported to MISO annually to monitor compliance.

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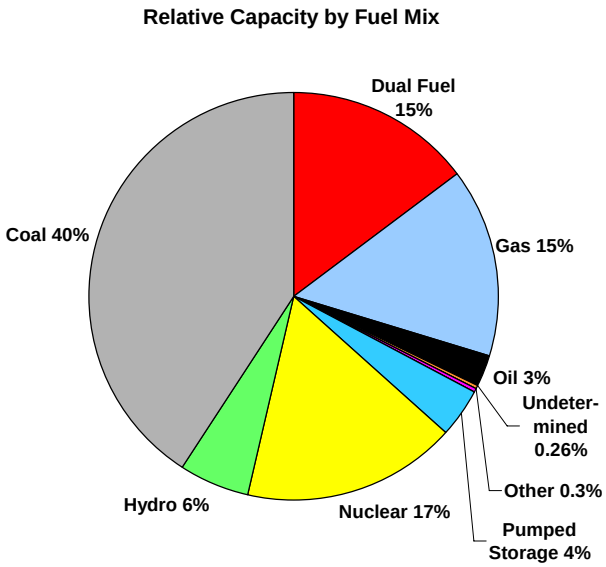
*RFC membership currently consists of 46 regular members and 19 associate members operating within 12 NERC balancing authorities. The members serve the electrical requirements of more than 72 million people in an area covering all of the states of Delaware, Indiana, Maryland, Ohio, Pennsylvania, New Jersey, and West Virginia, plus the District of Columbia; and portions of Illinois, Kentucky, Michigan, Tennessee, Virginia, and Wisconsin. Additional details are available on the Reliability*First *Web site (http://www.rfirst.org).*

SERC

Projected Total Internal Demand	166,344	MW
Interruptible Demand & DSM	5,286	MW
Projected Net Internal Demand	161,058	MW
Last Winter's Peak Demand	154,799	MW
Change	7.5	%
All-Time Winter Peak Demand	166,190	MW
Deliverable Internal Capacity	222,325	MW
Projected Purchases	1,469	MW
Projected Sales	2,540	MW
Net Capacity Resources	221,254	MW
Capacity Margin	27.2	%
Reserve Margin	37.4	%
With Uncommitted Resources		
Total Potential Resources	254,867	MW
Capacity Margin	36.8	%
Reserve Margin	58.2	%



Demand

The SERC Reliability Corporation (SERC) total internal demand for the 2006/2007 winter is forecast to be 166,344 MW, which is 11,545 MW (7.5%) higher than the actual 2005/2006 winter peak of 154,799 MW that occurred in December 2005. This projection is based on average historical winter weather. The forecast 2006/2007 winter peak (excluding new SERC members) is 149,518 MW, which is 2,038 MW (1.4%) higher than the forecast 2005/2006 winter peak (excluding new members) of 147,480 MW. These increases are due to typical load growth as well as milder temperatures during the 2005/2006 winter season. The all-time actual winter peak (excluding new members) was 150,308 MW, which occurred in January 2003.

Entergy and Southern subregions demand data reflect the reduction and reallocation of load due to Hurricane Katrina. As reported in the *2005/2006 Winter Assessment*, a portion of the Entergy Texas load was temporarily served by ERCOT, due to the impact of Hurricane Rita. Within weeks, Entergy was able to restore its system to a state that allowed it to transfer the load back and serve it reliably.

The SERC region has significant demand response programs. These programs allow demand to be reduced or curtailed when needed to maintain reliability. Interruptible demand and demand-side management capabilities for 2006/2007 winter are 5,285 MW (including 440 MW from new SERC members) as compared with the 4,824 MW reported last winter.

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, economics, and demographics
- Variance of forecasts due to such things as high and low economic scenarios and mild and severe weather
- Development of, and studies using, a suite of forecasts to account for the variables mentioned above

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

Planned firm sales across the SERC electrical borders total 2,540 MW and are comprised of 1,600 MW to FRCC, 927 MW to RFC, and 13 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 winter demand. The projected 2006/2007 winter capacity margin for SERC is 27.2%, which is higher than last year's projected capacity margin of 21.7%.

No major generator outages are planned for the winter that could impact reliability. Hydro reservoirs are currently below normal levels in the Southern, TVA, and VACAR subregions due to incipient drought conditions experienced during the summer season. However, these reservoir levels are expected to be sufficient to meet forecast peak demands and daily energy demands for the winter period. Several hydro facilities in the region are undergoing major rehabilitation such as rewinding of generators, turbine replacements, and switchyard work. 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 1,469 MW and are comprised of 1,111 MW from RFC and 358 MW from SPP. These firm purchases have been included in the capacity margin calculations for the region.

Although the SERC region does not implement 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 800 MW of committed capacity and no uncommitted capacity to be placed in service between March 1, 2006 and January 1, 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 recover from unplanned outages. Although such measures as emergency sales and purchases, activation of shared reserves, and voltage reductions have been used in the region during the past year, their use has not been on a frequency different than in previous years.

Merchant Generation

SERC has had significant merchant generation development over the past several years. 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 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 winter season. Over 250,000 MW of generating capability is expected to be connected in the region. This generation exceeds the forecast winter total peak demand by well over 80,000 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 different natural gas pipeline systems, reducing the dependence on any single interstate pipeline system. Moreover, the diversity of generating resources serving SERC member loads further reduces the region's risk.

Current projections indicate that the fuel supply infrastructure and fuel inventories for the winter period are adequate even considering possible impacts due to weather extremes. Additionally, new international gas supplies are continuing to emerge for the U.S. market.

Although 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 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 large amounts of firm and nonfirm power and allow systems to assist one another in the event of an emergency.

Approximately 130 miles of 161-kV, 230-kV, 345-kV, and 500-kV transmission lines are scheduled for completion prior to or during winter 2006/2007. SERC members invested approximately $1.26 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 2005 and plan to invest approximately $1.39 billion in 2006 and $1.44 billion in 2007.

Coordinated interregional transmission reliability and transfer capability studies for the 2006/2007 winter 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.

Assessment Process

Although SERC members plan for facility (transmission and generation) additions on an individual basis, SERC performs many assessment functions at the region level in order to provide coordination and ensure reliability.

An extensive data collection effort is required as part of the reliability assessment effort performed by SERC. Data collection is accomplished through a staff-facilitated Data Collection Task Force consisting of representatives from each reporting entity in SERC. SERC's relational database (Portal) is utilized extensively as the mechanism, via surveys and compliance and data forms, for gathering and compiling data. The collection of data for the EIA-411 has historically been a part of these reliability assessment activities as well.

In 2006, SERC consolidated a number of regional studies activities under the direction of the SERC Engineering Committee. These regional studies groups are responsible for the development of models and associated studies to ensure that planning activities in SERC are coordinated.

SERC utilizes its staff-facilitated Reliability Review Subcommittee (RRS) to perform assessments of future reliability and adequacy of the region and to prepare reports. Using information from the region's data collection efforts, the RRS makes an independent assessment of the ability of the region and subregions to serve their obligations given the demand growth projections, the amount of uncommitted or contracted capacity, etc. The RRS determines if the resource information submitted represents a reasonable and attainable plan. Also, the RRS annually performs a transmission assessment based on regional, interregional, and subregional reliability studies. The studies are reviewed and analyzed. If any additional study(ies) are required, the RRS will request the appropriate regional studies group(s) to perform the study(ies). The RRS's assessment provides a judgment on the ability of the SERC transmission system to operate securely under the expected range of operating conditions over the assessment period as required by the NERC Reliability Standards. The SERC Supplement on Reliability Assessments outlines SERC's interpretation and clarifies SERC's expectations of members with regard to the NERC Standards on Regional and Interregional Self-Assessment Reliability Reports, TPL-005, and TPL-006 (http://www.serc1.org/Pages/ComplianceContentPage.aspx?ID=25).

Subregions

Entergy

Demand — The total internal demand for the 2006/2007 winter season is forecast to be 21,654 MW based on normal weather conditions. This is 864 MW (3.8%) lower than the forecast 2005/2006 winter peak demand of 22,518 MW and is 212 MW (1.0%) higher than the actual 2005/2006 winter peak demand of 21,442 MW. The decline in forecast is due to the inclusion of load reductions and reallocations for the area affected by Hurricane Katrina. The increase over last winter's actual peak is due to load growth and milder than normal weather conditions during the 2005/2006 winter.

Resource Assessment — The projected capacity margin in the subregion is 40.1% as compared to 31.7% last year. This increase is primarily due to the acquisition of new network resources (Perryville 718 MW and Attala 463 MW) and loss of load due to Hurricanes Katrina and Rita. Capacity in the subregion should be adequate to supply forecast demand. 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. No reliability concerns are anticipated for the upcoming peak season as a result of the after effects of the 2005 hurricane season. No major generating unit outages or transmission facility outages that would impact system reliability are planned for the 2006 winter season.

Transmission Assessment — Several transmission projects to increase system reliability are scheduled for completion prior to or during winter 2006/2007 in the Entergy subregion. A second circuit from Entergy's Sterlington 500-kV station to Perryville 500-kV station, both in north Louisiana, will be completed in late 2006. A second 500/230-kV autotransformer at Entergy's Ray Braswell station in Mississippi is scheduled for service in December 2006. These transmission system additions complete an upgrade package to enable long-term service from the Perryville generation plant. AECI has scheduled improvements to its 161-kV and 69-kV systems. In total, over 32 miles of 230-kV and 500-kV transmission lines and several station reliability improvement projects were completed with approximately six miles of 500 kV additions scheduled for completion prior to or during the 2006/2007 winter season. Coordinated studies with neighboring regions and the other SERC subregions indicate that transmission transfer capability will be adequate on all interfaces this winter to support reliable operations.

Gateway

Effective January 1, 2006, SERC membership expanded to include several members in the central part of the country, resulting in the creation of a fifth SERC subregion (Gateway subregion). The Gateway subregion is comprised of the following SERC members: Ameren Services Company, City of Columbia, Missouri, Electric Energy, Inc., Illinois Municipal Electric Agency, Southern Illinois Power Cooperative, and Soyland Power Cooperative, Inc.

Demand — The total internal demand for the 2006/2007 winter season is forecast to be 14,329 MW based on normal weather conditions. This is 182 MW (1.3%) lower than the actual 2005/2006 winter peak demand of 14,511 MW.

Resource Assessment — The projected capacity margin in the Gateway subregion is 46.2%. In the last few years, a number of IPP generators were connected in the Gateway subregion but were not designated to serve load. For 2006 summer, Gateway members purchased some of this previously unclaimed IPP generation. Subregion-wide, available generation levels have not changed significantly from 2005 to 2006, but some previously undesignated generation was committed to serving load in the subregion for

2006 summer. This was reflected in the reported capacity margin increase for the subregion. However, barring intervention, beginning January 1, 2007 the retail load in the Illinois service territory will be 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 may or may not be located within the Gateway subregion.

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

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, Ameren's St. Francois – Lutesville 345-kV line and 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 2006/2007 winter season. In the short term, constraints will be addressed through local operating procedures, generation redispatch, and the TLR process to maintain reliability.

Transmission Assessment — The addition of the Callaway – Franks 345-kV line is scheduled to be in service by December 2006. This line will provide loading relief to the Bland – Franks 345-kV line, improve reliability in central Missouri, and serve as a supply to a new station in the area by summer 2008. In total, 30 miles of 161-kV and 345-kV transmission lines and several station reliability improvement projects were completed for the summer season with approximately 54 more miles of 345 kV additions scheduled for completion prior to or during the 2006/2007 winter season. Coordinated studies with neighboring regions and the other SERC subregions indicate that transmission transfer capability will be adequate on all interfaces this winter to support reliable operations.

Southern

Demand — The total internal demand for the 2006/2007 winter season is forecast to be 40,541 MW based on normal weather conditions. This is 1,849 MW (4.8%) higher than the forecast 2005/2006 winter peak demand of 38,692 MW and 2,027 MW (5.3%) higher than the actual 2005/2006 winter peak demand of 38,514 MW. These increases were driven by load growth, the increase in contribution of weather sensitive loads in the forecast, and mild temperatures during last winter's peak period.

Resource Assessment — The projected capacity margin in the Southern subregion is 25.8% compared to 20.1% 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 VASTE (VACAR (Virginia/Carolinas), AEP, Southern, TVA, Entergy) Winter Reliability Study indicate assistance can be imported into the Southern subregion during the upcoming winter peak. Analysis for the most recent OASIS postings indicates simultaneous import capability to be over
5,100 MW for the most restrictive winter 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 are expected to be operational by January 1, 2007.

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

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 rather than by loading within the subregion. 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 Assessment — All major outages due to Hurricane Katrina returned to service prior to the 2006 summer season. Substantial reduction of load is anticipated in Mississippi during a multi-year rebuilding cycle due to the widespread destruction of homes and businesses. In total, over 260 miles of 230-kV and 500-kV transmission lines and several station reliability improvement projects were completed with approximately 50 more miles of 230 kV and 500 kV additions scheduled for completion prior to or during the 2006/2007 winter season.

TVA

Effective January 1, 2006, two new SERC members, East Kentucky Power Cooperative (EKPC) and Big Rivers Electric Coop. (BREC), joined the TVA subregion.

Demand — The total internal demand for the 2006/2007 winter season is forecast to be 35,090 MW based on normal weather conditions. The total internal demand (excluding the new members) is forecast to be 31,594 MW, which is 722 MW (2.0%) higher than the forecast 2005/2006 winter peak demand of 30,872 MW. The total internal demand for 2006/2007 is projected to be 4,218 MW (13.7%) higher than the actual 2005/2006 winter peak of 30,872 MW.

Resource Assessment — The projected capacity margin in the subregion is 15.7% compared to 12.6% last winter. Capacity in the subregion should be adequate to supply forecast demand.

The system had been operating without the Roane transformer bank (1,350 MVA) following failure of one phase in January 2005. The bank was returned to service in April 2006. New transformers being shipped to the 500-kV Madison substation were on barges in New Orleans during Hurricane Katrina and were subsequently found to have experienced high impact forces. However, TVA's standardization of transformer design allowed substitution of the transformers that were intended for the new Bradley 500-kV substation. The Madison second bank installation will be completed in March 2007 and is required in service prior to the Browns Ferry Nuclear Unit 1 restart in spring 2007.

Operational Issues — No reliability problems are anticipated on the transmission systems of the TVA subregion members this winter. The TVA transmission system has experienced large and volatile flows in recent years and these flows may occur again this winter. 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.

EKPC's Avon 345/138-kV autotransformer is expected to be a constraint for 2006/2007 winter. This transformer was a constraint on several occasions in 2005 during periods of significant north-south transfers. EKPC has implemented a Dynamic Thermal Circuit Rating (DTCR) program to maximize the power flow through the 345/138-kV autotransformer at the Avon substation. The DTCR program will be implemented as an interim measure to more accurately identify the transformer limit using actual

conditions. EKPC has identified transmission system additions to be made by 2007 summer that will greatly reduce the power flows on the Avon transformer.

Transmission Assessment — In total, approximately 105 miles of 161-kV and 500-kV transmission lines and several station reliability improvement projects were completed with approximately 13 more miles of 230 kV improvements scheduled for completion prior to or during the 2006/2007 winter season. Coordinated studies with RFC members and the other SERC subregions indicate that transmission transfer capability will be adequate on all interfaces this winter to support reliable operations.

VACAR

Demand — The total internal demand for the 2006/2007 winter season is forecast to be 55,730 MW based on normal weather conditions. This is 435 MW (0.8%) higher than the forecast 2005/2006 winter peak demand of 55,295 MW and 5,281 MW (10.5%) higher than the actual 2005/2006 winter peak demand of 50,449 MW, due to the milder than normal weather last winter.

Resource Assessment — The projected capacity margin in the subregion is 25.1% compared to 23.1% last winter. Capacity in the subregion should be adequate to supply forecast demand.

Lee units 7C and 8C (combustion turbines totaling 80 MW) are expected to come on-line in October 2006, prior to the winter peak season. Cross unit 3 (620 MW Coal) is expected to come on-line in January 2007. All are committed to serving load in the subregion. In January 2007, a VACAR member will complete the purchase of an IPP combustion turbine plant, totaling 825 MW. Subregion-wide, this will not significantly change the total available generation, but this previously undesignated generation will then be committed to serving load in the subregion.

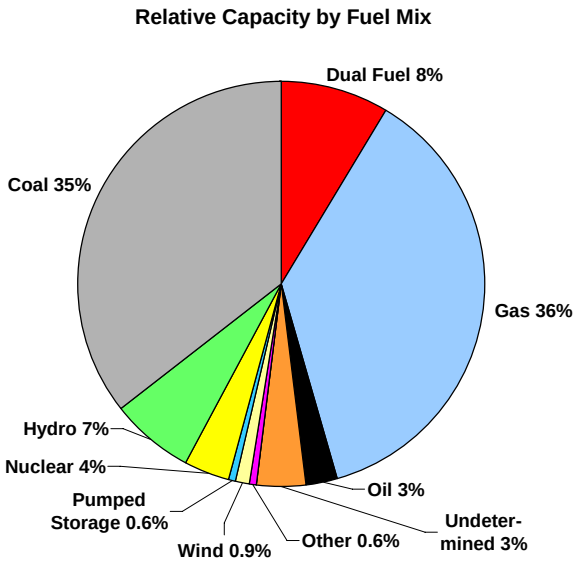
Operational Issues — No reliability problems are anticipated on the transmission systems of the VACAR subregion members this winter. Coordinated studies for the winter season were performed with RFC members and the other SERC subregions. These studies indicate that transmission transfer capability will be adequate on all interfaces this winter to support reliable operations. The Duke-to-TVA 161-kV tie could experience heavy loading this winter, similar to previous years since this tie is responsive to many transaction paths. An operating procedure is in place to maintain reliability should this heavy loading occur.

Transmission Assessment — 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. The Lake Murray 230-kV loop-in and 230/115-kV substation will be completed by the winter. The Riverview – Ripp 230-kV (circuits 1 and 2) bundling project was completed prior to the summer 2006 season to relieve internal generation deliverability constraints. The Lynnhaven – Virginia Beach transmission line was converted to 230-kV operation during last winter to relieve contingency constraints. Numerous other additions, conversions, and projects to increase capacity were completed since the previous winter season. In total, over 200 miles of 230-kV and 500-kV transmission lines and several station reliability improvement projects were completed with approximately 20 more miles of 230 kV additions scheduled for completion prior to or during the 2006/2007 winter season.

The SERC region includes portions of 16 states (Alabama, Georgia, Mississippi, Missouri, North Carolina, South Carolina, Tennessee, Arkansas, Louisiana, Florida, Oklahoma, Illinois, Texas, Iowa, Virginia, and Kentucky) in the southeastern and central United States, covers an area of approximately 560,000 square miles, and serves almost 40 million customers. SERC is divided geographically into five diverse subregions that are identified as Entergy, Gateway, Southern, TVA, and VACAR. SERC and its five subregions are all summer peaking. Currently totaling in excess of 50, SERC membership is comprised of investor-owned, municipal, cooperative, state and federal systems, RTOs/ISOs, merchant electricity generators, and power marketers. Additional information can be found on the SERC Web site (www.serc1.org).

SPP

Projected Total Internal Demand	30,183	MW
Interruptible Demand & DSM	439	MW
Projected Net Internal Demand	29,744	MW
Last Winter's Peak Demand	31,764	MW
Change	(5.0)	%
All-Time Winter Peak Demand	30,686	MW
Deliverable Internal Capacity	46,784	MW
Projected Purchases	1,898	MW
Projected Sales	1,627	MW
Net Capacity Resources	47,055	MW
Capacity Margin	36.8	%
Reserve Margin	58.2	%
With Uncommitted Resources		
Total Potential Resources	55,137	MW
Capacity Margin	46.1	%
Reserve Margin	85.4	%



Demand

The winter noncoincident total internal demand is projected to be 30,183 MW, which is 5% lower than the 2005 actual winter peak monthly total internal noncoincident demand of 31,764 MW but 0.2% higher than the projected peak load of 29,480 MW for 2005/2006 winter. Although actual demand is very dependent upon weather conditions and typically includes the effects of interruptible loads, forecasted net internal demands are based on normal weather conditions and do not include the effects of interruptible loads. The forecasted values are 397 MW of interruptible demand and 42 MW of load management. Southwest Power Pool (SPP) is a summer-peaking system. Winter peaks are typically less than those experienced in the summer.

SPP has a total of approximately 1,627 MW of sales to other regions for the winter season. Sales are composed of 48 MW to ERCOT, 107 MW to RFC, 1,002 MW to SERC, and 470 MW to WECC. This number includes some nonfirm sales from merchant generation, municipalities, and other neighboring markets.

Each SPP member annually provides to SPP a ten-year forecast of peak demand and net energy requirements. The forecasts are developed in accordance with generally recognized methodologies and with the following principles:

- Each member selects its own demand forecasting methodology and establishes its own forecast.
- Each member forecasts demand based on expected weather conditions.
- Methods used, factors considered, and assumptions made are submitted along with the annual forecast to SPP.
- Economic, technological, sociological, demographic, and any other significant factors are considered when producing the forecast.

The resultant SPP forecast is the total of the member forecasts. High- and low-growth rates and unusual weather scenario bands are then produced for the SPP regional and subregional demand and energy forecasts. Peak demand would be increased by 2.9% in the case of extreme weather.

Resource Assessment

The SPP projected capacity margin based on committed resources is expected to be 37.7% for the 2006/2007 winter, which is similar to last winter's projected capacity margin. This is significantly above the 12% minimum criteria for the region. No significant capacity additions are forecasted in SPP before winter 2006/2007.

SPP has a total of approximately 1,648 MW of purchases from other regions, IPP's mostly within SPP footprint, and various marketers with unknown sources both within and outside of SPP. Regional purchases that may include some short-term nonfirm contracts are composed of 218 MW from ERCOT, 249 MW from MRO, and 1,181 MW from SERC.

Fuel

With one exception (Eufaula, OK), SPP hydro reservoirs have improved to above normal for this time of year. Normal hydro capacity is expected for the winter conditions. In general, the energy output from hydro does not have a regional impact since only a small percentage of SPP capacity is hydro. All fuel supplies throughout the winter are expected to be adequate during the projected peak winter demand period. There are no known fuel transportation issues affecting capability during peak periods. It is anticipated that fuel supplies will continue to be adequate for the winter operating season. During peak periods, operators typically minimize generation outages and rely on alternate fuel capabilities built into generation fleets to increase fuel diversity and minimize the effects of potential fuel supply disruptions. Use of specific fuel infrastructures is typically based on economic conditions surrounding the types of fuels, prevailing economics on the grid, and the availability of external purchased power. During peak winter conditions, operators typically use some alternate fuel unit dispatch depending on system economics or fuel-supply infrastructure capabilities and design.

Transmission Assessment

SPP is the first transmission provider to implement an aggregate transmission service processing methodology – SPP OATT Attachment 'Z' (http://www.spp.org/publications/SPP_Tariff.pdf). The aggregate study process will allow all requests to be evaluated together. Additionally, it will provide for cost sharing and cost recovery. When multiple customers request service that similarly impacts transmission facilities, the aggregate study will allow these customers to share the cost of upgrading these facilities. Any costs paid by a customer above the transmission service base rate may be recovered with interest if new point-to-point service is requested across the upgraded facility. This will significantly enhance the way transmission service requests are processed and expedite regional transmission expansion.

During the winter of 2006/2007, no transmission constraints are anticipated that would affect the deliverability of generation. The transmission system within SPP is expected to perform reliably during the 2006/2007 winter load season. Regional studies indicated that import capabilities for the SPP region are adequate for the winter season. No significant new generation or transmission additions are planned to be in service prior to this winter season.

In July, Westar completed the conversion of the Morris – McDowell Creek 115-kV line to 230-kV operation. Westar also added a 230/115-kV transformer at McDowell Creek. Since last winter, SPP members have completed 21 projects that amount to $28 million of investment for expanding and upgrading the existing transmission system.

SPP participates in interregional winter transmission assessments with MRO, RFC, and SERC to evaluate the transfer capability between SPP and neighboring reliability regions. The recently performed joint study has indicated adequate transfer capabilities between these regions.

Operational Issues

There are no known unusual operating conditions expected to impact reliability for the upcoming winter. There are no scheduled maintenance outages of operational concern.

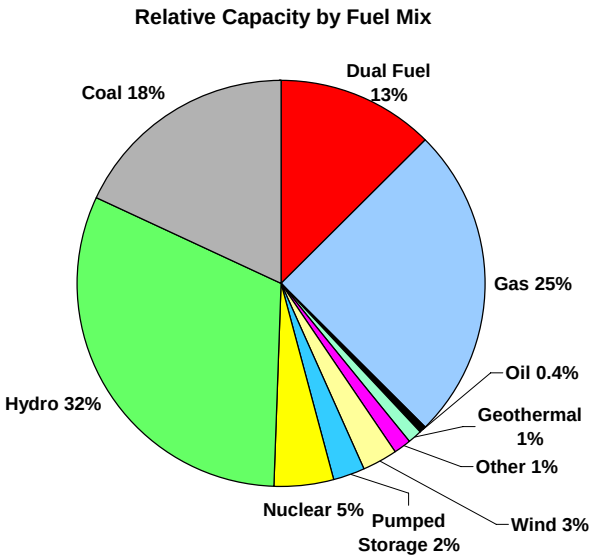
Assessment Process

SPP annually uses the Model Development Working Group to gather information and coordinate data for use in the development of new model sets. SPP models contain grandfathered transactions as well as SPP OATT transactions, and the projected renewal rights for all such transactions. These models are used to determine necessary transmission upgrades and generation dispatches for providing reliable transmission service from designated resources to support firm off-system sales and the native load requirements within the SPP footprint.

SPP, a reliability coordinator in the southwest quadrant of the Eastern Interconnection, currently consists of 46 members, serves more than 4 million customers and covers a geographic area of 400,000 square miles containing a population of over 18 million people. In covering a wide political, philosophical, and operational spectrum, SPP's current membership consists of 13 investor-owned utilities, seven municipal systems, nine generation and transmission cooperatives, two state authorities and one federal government agency, three independent power producers, and 12 power marketers. SPP is more than 350 electric industry employees on various organizational groups that bring together industry-wide expertise to deal with tough reliability and equity issues. An administrative and technical staff of approximately 250 persons facilitates the organization's activities and services. Additional information can be found on the SPP Web site (www.spp.org).

WECC

Projected Total Internal Demand	130,255	MW
Interruptible Demand & DSM	2,215	MW
Projected Net Internal Demand	128,040	MW
Last Winter's Peak Demand	128,934	MW
Change	1.0	%
All-Time Winter Peak Demand	128,934	MW
Deliverable Internal Capacity	177,846	MW
Projected Purchases	600	MW
Projected Sales	207	MW
Net Capacity Resources	178,239	MW
Capacity Margin	28.2	%
Reserve Margin	39.2	%
With Uncommitted Resources		
Total Potential Resources	178,239	MW
Capacity Margin	28.2	%
Reserve Margin	39.2	%



Demand

The aggregate Western Electricity Coordinating Council (WECC) 2006/2007 winter total internal demand is forecasted to be 130,255 MW (U.S. systems 107,524 MW, Canadian systems 21,258 MW, and Mexican system 1,473 MW). The forecast is based on normal weather conditions and is 1.0% above last winter's actual peak demand of 128,934 MW, which was established under generally normal temperatures in the region. The 2006/2007 winter total internal demand forecast is 2.4% greater than the 2005/2006 winter total internal demand forecast of 127,214 MW. The internal demand forecast includes 609 MW of direct control demand-side management capability and 1,606 MW of interruptible demand capability. WECC does not perform any quantitative analyses of load variability due to extreme weather conditions. However, many load-serving entities perform weather related studies with high, expected, and low demand expectations when creating their load forecast.

Resource Assessment

For the peak winter month of December, WECC's one-hour capacity margin is expected to be 28.2%, which corresponds to a 39.2% reserve margin. WECC's capacity margin last year was 29.3% with a reserve margin of 41.5%. WECC has not established a region-wide resource adequacy criteria. However, several individual entities within the region have planning margins that generally range from 12% to somewhat over 15%. WECC's net operating capacity has increased by 863 MW from 176,983 MW in the winter of 2005/2006 to 177,846 MW in the winter of 2006/2007. WECC's expected net capacity resources of 178,239 MW include 600 MW of firm capacity purchases from outside the WECC, 388 MW from SPP, and 212 from MRO, and 207 MW of sales to SPP. Net capacity additions during the 2006/2007 winter period are expected to total about 222 MW; significant changes include 91 MW of nameplate wind capability, 20 MW of new hydro capacity, 80 MW of geothermal capacity, 9 MW of landfill gas-fired generation, and 22 MW of combustion turbines. For this winter season, there are 207 MW firm capacity commitments anticipated to external areas.

It is anticipated that hydro conditions throughout the region will be sufficient to meet both peak demand and the daily demand this winter. However, since a significant portion of WECC's hydroelectric

resources are energy-limited, the region's effective capacity margin could decline to around 25.2% should the Pacific Northwest experience energy and other operational limitations concurrent with high sustained peak demands.

WECC has eight back-to-back direct current ties to the Eastern Interconnection with a combined transfer capability of almost 1,500 MW. Net capacity imports of 393 MW are planned for the 2006/2007 winter period. The net non-simultaneous capacity imports for the 2005/2006 winter were about 400 MW. It has been reported that the capacity imports have firm resource and associated firm transmission commitments.

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.

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. These diverse supply areas are typically not affected by the hurricanes that have hit the Gulf Coast. Plant operators have commented that natural gas prices may remain high due to the Gulf Coast supply interruptions, but they do not expect gas supply interruptions. Significant pipeline capability exists between the western gas supply systems and gas supply systems to the east and available gas supplies could be reduced even if western production remains stable or increases somewhat. WECC's fuel supply survey indicates that coal deliveries have returned to pre-Powder River Basin coal field disturbance levels. The operators of those plants report that inventories have been rebuilt to necessary supply levels for the projected 2006/2007 winter demand.

Transmission Assessment

WECC entities prepare extensive operating studies that model the transmission system under a number of load and resource scenarios and develop operating procedures to maintain safe and reliable operations. The resources reported in this assessment have been reduced to reflect deliverability constraints identified by the operating studies. Many operating entities within the region have reported that they did not experience significant new flow patterns last winter. Slightly different flow patterns are expected on the western Colorado paths and from Arizona to California. However, these flows are expected to be well within the established transfer limits of these paths. 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. Consequently, the frequency and magnitude of schedule curtailments on constrained paths may increase compared with last winter. Reactive reserve margins are expected to be adequate for all peak load conditions. Close attention to maintaining appropriate voltage levels is expected to prevent voltage problems.

WECC and regional entities have several processes in place that relate to generation deliverability. For example, 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. As noted in the transmission section above, resource deliverability limitations identified by transfer capability studies, interconnection agreement studies, etc., are reflected in the net operable capabilities presented in this assessment.

Operational Issues

WECC does not expect major generating unit outages, transmission facility outages, or unusual operating conditions that would adversely impact reliable operations this winter. No environmental or regulatory restrictions have been reported that are expected to adversely impact reliability.

Subregions

Northwest Power Pool (NWPP) Area

Demand — NWPP is a winter-peaking area. The 2006/2007 winter coincident peak demand forecast of 58,400 MW for the combined northwestern United States and Canadian areas is 0.2% above last year's actual coincident peak load of 58,267 MW, and 1.4% above last winter's temperature-corrected coincidental actual peak demand of 57,567 MW when the weighted composite temperature was 2° F below normal for the NWPP area. The 2006/2007 winter total internal demand forecast is 1.6% greater than the 2005/2006 winter total internal demand forecast of 57,500 MW. The winter peak demand forecast includes an average 240 MW of load management and interruptible demand.

Resource Assessment — The NWPP is comprised of all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, Wyoming, a small portion of northern California, and the Canadian provinces of Alberta and British Columbia. The NWPP, in collaboration with its members, has conducted an assessment of reliability to evaluate the ability of the power pool to meet its load requirements during the 2006/2007 winter. Its assessment indicates the northwestern region will be able to meet firm loads and required forced outage reserves for the 2006/2007 winter operations, assuming normal temperature conditions. Under normal weather conditions, NWPP does not anticipate depending on imports during winter peak demand periods. As of the end of July, the NWPP reports that the Coordinated System hydro reservoir levels had refilled to approximately 93% of the energy content curve.

Hydro facilities are operated to optimize the use of available water throughout the year while assuring all competing uses are evaluated. Although available capacity margin at time of peak can be calculated to be greater than 20%, this can be misleading. The NWPP resource mix is approximately 60% hydroelectric, which requires adequacy measurements to shift from capacity to firm energy. 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 hydroelectric resource capability in the NWPP subregion has been reduced by 3,653 MW from 46,383 MW to 42,730 MW due to the impact that upstream or downstream operations might have on hydro facilities in the middle of the reference area, scheduled maintenance, and other factors.

The FELCC is highly dependent upon the availability of water for hydroelectric generation. The energy and other operational limitations, combined with high sustained peak demands, may reduce the hydroelectric sustained capability by up to 7,000 MW from about 43,000 MW. The one-hour calculated capacity margin for the peak hour of the peak month is 23.5%. However, the limitations associated with sustainable capability for a hydroelectric system, combined with a widespread cold weather event, yields a sustainable capacity margin closer to 15.9%.

The capacity margin in the NWPP region appears to be adequate for the upcoming winter season. The Canadian subregion of British Columbia and Alberta forecasts a capacity margin of 7.6% for the 2006/2007 winter assessment. However, the subregion calculation does not include approximately 1,200 MW of import capability from the United States. If the U.S. import capability is added to the reported resources, the subregion's capacity margin increases to 12.3%.

One factor that can affect electricity demand and margins in the NWPP area is extremely cold weather, often called an "arctic express." This is a one in twenty year event that is known and forecast far enough in advance to permit necessary preparations to be made. In the event of a power or energy emergency caused by an arctic express, the NWPP has an Emergency Energy Plan (EEP) to address the situation. As part of the EEP, the Emergency Response Team (ERT) will work with all parties in pursuing options to resolve the emergency including but not limited to load curtailments and or imports of additional power from other areas outside of the power pool.

Operational Issues — Constrained transmission paths within the NWPP area have been identified, operating studies modeling these constraints have been performed, and operating procedures have been developed to ensure safe and reliable operations.

California–Mexico Power Area

Demand — The California-Mexico area is summer-peaking. The 2006/2007 winter peak demand forecast of 42,566 MW is 1.6% above last winter's actual peak demand of 41,910 MW. The 2006/2007 winter total internal demand forecast is less than 0.1% lower than the 2005/2006 winter total internal demand forecast of 42,593 MW. The forecast peak demand includes 1,310 MW of interruptible demand and load management.

Resource Assessment — The California-Mexico area is anticipating historically normal hydro conditions. These water levels are expected to be sufficient to supply capacity and energy for the winter season. The hydro capacity in the California-Mexico subregion has been reduced by 3,885 MW, from 10,841 MW to 7,717 MW, to reflect adverse hydroelectric generation conditions and hydro capacity experience with runoff conditions and water user requirements. The projected capacity margin for the peak month is 22.2%.

Transmission Assessment — Although several major constrained transmission paths have been upgraded in recent years, path constraints still exist. However, the winter peak demands are significantly less than summer peak demands, so path constraints during the winter period are less of a concern. Operating procedures are in place to manage any high loading conditions that may occur during the winter. Entities within the area report having no concerns with maintaining adequate reactive reserve margins.

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

Rocky Mountain Power Area

Demand — The Rocky Mountain Power Area's peak demand may occur in either summer or winter. The 2006/2007 winter peak demand forecast of 9,604 MW is 0.8% above last winter's actual peak demand of 9,528 MW. The 2006/2007 winter total internal demand forecast is 3.3% greater than the 2005/2006

winter total internal demand forecast of 9,296 MW. The forecast peak demand includes 111 MW of interruptible demand and load management capability.

Resource Assessment — Hydro conditions for the 2006/2007 winter are expected to be normal and similar to that of the 2005/2006 winter season. 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 projected capacity margin for the peak month is 27.0%.

Transmission Assessment — 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 winter to provide line loading relief for these paths.

Arizona-New Mexico-Southern Nevada Power Area

Demand — This is a summer-peaking area. The 2006/2007 winter peak demand forecast of 18,146 MW is 5.9% above last winter's actual peak demand of 17,130 MW. The 2006/2007 winter total internal demand forecast is 1.6% greater than the 2005/2006 winter total internal demand forecast of 17,856 MW. The forecast for the area includes 336 MW of load management and interruptible demand capability.

Resource Assessment — Following several years of good precipitation in this area the hydro conditions are anticipated to be near normal and are deemed to be sufficient for the winter season. However, hydro resource capability has been reduced by 942 MW from 6,169 MW to 5,227 MW under normal hydro conditions in the Rocky Mountain Power Area and the Arizona-New Mexico-Southern Nevada Power Area subregions. The projected capacity margin for the peak month is 47.6%.

Transmission Assessment — 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.

Fuel — Fuel supplies are expected to be adequate to meet winter peak demand conditions. The physical gas commodity and pipelines that supply this area have proven very reliable. In addition, firm coal supply and transportation contracts are in place, and sufficient coal inventories are anticipated for the winter season.

WECC's 180 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. The capacity margins discussed in the subregional assessments assume the planned construction of 20,720 MW of net new generation, which is significantly less than the net planned capacity additions of 25,155 MW reported last year for the 2005–2014 time period. Generation decreased by about 1,150 MW in 2005. 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.

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
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 Council
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
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

Reliability Assessment Subcommittee

Kevin J. Dasso
Chairman
Sr. Director, Engineering & Planning
Pacific Gas & Electric Company

John E. Odom, Jr.
FRCC Representative
Manager of System Planning
Florida Reliability Coordinating Council

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

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

Mark J. Kuras
RFC Alternate
Senior Engineer, Interregional
Coordination and Compliance
PJM Interconnection, L.L.C.

Bernard M. Pasternack, P.E.
RFC Representative
Managing Director, Transmission
Asset Management
American Electric Power

H. Clay Young
SERC Representative
Manager of Transmission
South Carolina Electric & Gas Company

Mak Nagle
SPP Representative
Manager, Engineering
Southwest Power Pool

James Leigh-Kendall
WECC Representative
Supervisor, Power System Assessments
Sacramento Municipal Utility District

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

William O. Bojorquez
Vice Chairman and ERCOT Representative
Director, System Planning
Electric Reliability Council of Texas, Inc..

John Lawhorn
ISO/RTO Representative
Manager, Economic Studies
Midwest ISO, Inc.

Robert Snow
FERC Representative
Senior Electrical Engineer, Reliability Division
Federal Energy Regulatory Commission

Scott Beecher
FRCC Alternate
Staff Engineer
Florida Reliability Coordinating Council

Christopher Plante
MRO Alternate
Director of Transmission Analysis
WPS Resources Corporation

Glenn P. Catenacci, P.E.
RFC Alternate
Staff Engineer
Public Service Electric and Gas Company

Jeffrey L. Mitchell
RFC Alternate
Director, Engineering
Reliability*First* Corporation

Poonum Agrawal
DOE Liaison
Program Manager/Engineer
U.S. Department of Energy

David R. Nevius
Senior Vice President and
Director of Reliability Assessment & Performance Analysis
North American Electric Reliability Council

Christopher J. Lada
NERC Technical Analyst
North American Electric Reliability Council

Karol A. Lane
Administrative Assistant
North American Electric Reliability Council