2006
Long-Term
Reliability Assessment

The Reliability of the
Bulk Power Systems
In North America

North American Electric Reliability Council
October 2006

TABLE OF CONTENTS

INTRODUCTION

Mission of the Electric Reliability Organization

NERC's mission is to improve the reliability and adequacy of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits 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 Electric Reliability Organization (ERO), NERC is subject to audit by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada.

On July 20, 2006, the Federal Energy Regulatory Commission (FERC) 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 Long-Term Reliability Assessment* is the first assessment filed by NERC in its capacity as the ERO.

How This Assessment was Prepared

NERC, through its Reliability Assessment Subcommittee of the NERC Planning Committee, prepared this *2006 Long-Term Reliability 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 key findings, actions needed, and assessment summary represent NERC's independent judgment of the reliability and adequacy of the bulk power systems in North America as existing and as planned, and what is needed to effect improvement.

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 as of March 24, 2006. Where possible, updates to the data and information have been incorporated. The subcommittee reviewed regional summaries of projected peak electric demand, energy, and capacity resources; appraised regional plans for new electric generation resources and transmission facilities; and assessed the potential effects of changes in technology, market forces, legislation, regulations, and governmental policies on the reliability of future electricity supplies. Neither NERC nor the subcommittee makes any projections or draws any conclusions in this report regarding expected electricity prices for the assessment period.

The data and information submitted by the regional reliability organizations was based on their member systems' projections as of March 24, 2006. Where possible, updates to the data and information have been incorporated. 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 or confusing information was presented. Summaries of the supporting data are contained in the tables and figures throughout the report.

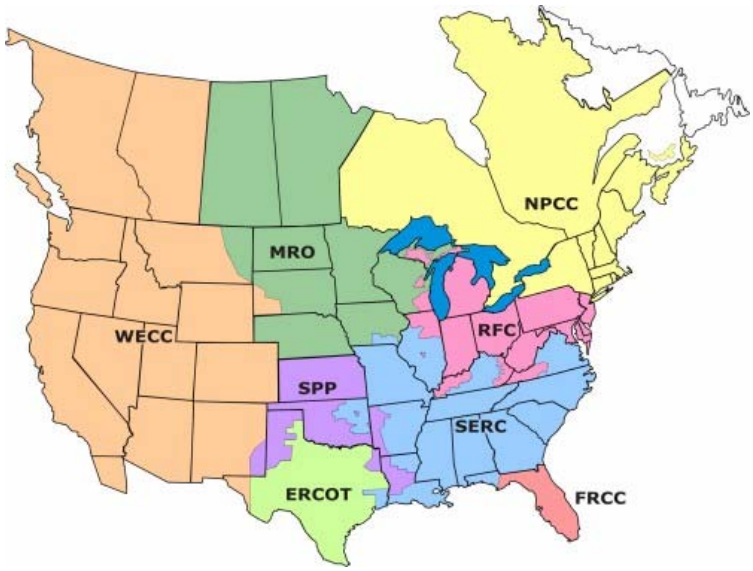
This assessment is based on several assumptions:

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

Summer 2006 Heat Wave

The widespread heat wave experienced in late July and early August 2006 caused peak demands to exceed forecasts and required utility system operators, customers, and government agencies to implement emergency procedures in some areas. While some localized distribution outages did occur, no bulk power system involuntary customer load interruptions were needed, mainly because generating capacity performed extremely well during this period.

Figure 1: NERC Regional Reliability Councils as of October 16, 2006



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

Key Findings and Actions Needed[1]

Electric Capacity Margins Continue to Decline — Action Needed to Avoid Shortages

- Electric capacity margins will decline over the 2006–2015 period in most regions.
- The projected decline in margins reflects a short-term resource acquisition strategy that has been the norm for most of the past ten years.
- Electric utilities forecast demand to increase over the next ten years by 19 percent (141,000 MW) in the United States and 13 percent (9,500 MW) in Canada, but project committed resources to increase by only 6 percent (57,000 MW) in the U.S. and by 9 percent (9,000 MW) in Canada.
- The projected increase in committed resources assumes that all resource additions that are in various stages of planning, licensing, or construction will come into service on schedule.
- Available capacity margins, which include only committed resources, are projected to drop below minimum regional target levels in ERCOT, MRO, New England, RFC, and the Rocky Mountain and Canada areas of WECC in the next 2–3 years, with other portions of the Northeastern U.S. Southwest, and Western U.S. reaching minimum levels later in the ten-year period.
- Over 50,000 MW of uncommitted resources exist today NERC-wide that either do not have firm contracts or a legal or regulatory requirement to serve load, lack firm transmission service or a transmission study to determine availability for delivery, are designated or classified as energy only resources, or are in mothballed status because of economic considerations.
- Over the next ten years, uncommitted resources will more than double with the inclusion of generation currently under construction or in the planning stage, but which is not yet under contract to serve load.
- In many cases, these uncommitted resources represent a viable source of incremental resources that can be used to meet minimum regional target levels.
- The lack of adequate transmission emergency transfer capability or transmission service agreements could limit the ability to deliver available resources from areas of surplus to areas of need.
- Demand reductions have been achieved through various demand response programs. Direct control load management and interruptible demand programs represent about 2.5 percent of summer peak demand (20,000 MW) in the U.S. and about 2.5 percent of winter peak demand (2,500 MW) in Canada. New or expanded demand response programs and initiatives can further reduce peak demands.[2]

[1] The "Actions Needed" do not represent mandatory requirements, but rather NERC's independent judgment of those steps that will help improve reliability and adequacy of the bulk power systems of North America.
[2] Demand response programs include: direct-control load management, interruptible demand contracts, peak demand pricing, energy efficiency standards and improvements, etc.

- Long-term electricity supply adequacy requires a broad and balanced portfolio of generation and fuel types, transmission, demand response, renewables, and distributed generation; all supply-side and demand-side options need to be available.

Actions Needed:

- Electric utilities[3] need to commit to add sufficient supply-side or demand-side resources, either through markets, bi-lateral contracts, or self supply, to meet minimum regional target levels.

- Electric utilities, with support from state, federal, and provincial government agencies, need to actively pursue effective and efficient demand response programs.

- Electric utilities and resource providers need to coordinate long-term resource plans with transmission providers to ensure sufficient transmission capacity is available to deliver resources to load areas.

- NERC, in conjunction with regional reliability organizations and electric utilities, will evaluate the implications of the 2006 summer heat wave on future demand forecasts.

- NERC, in conjunction with regional reliability organizations, electric utilities, resource planning authorities, and resource providers, will address the issue of "uncommitted resources" by establishing more specific criteria for counting resources toward supply requirements.

- NERC will expedite the development of its new reliability standard on resource adequacy assessment that will establish parameters for taking into account various factors, such as: fuel deliverability; energy-limited resources; supply/demand uncertainties; environmental requirements; transmission emergency import constraints and objectives; capability to share generation reserves to maintain reliability, etc.

Construction of New Transmission is Still Slow — Continues to Face Obstacles

- Expansion and strengthening of the transmission system continues to lag demand growth and expansion of generating resources in most areas.[4]

- While peak demand is projected to increase over the next ten years by 19 percent in the U.S. and by 13 percent in Canada, total transmission miles are projected to increase by less than 7 percent in the U.S. and 3.5 percent in Canada.

- The transmission system requires additional investment to address reliability issues and economic impacts.

- Without expanded transmission system investment, grid congestion will increase, making it more difficult for available supply to meet demands and to allow full utilization of capacity/demand

[3] "Electric utilities" in this context refers to load-serving entities whose responsibility it is to secure energy, transmission, and related interconnected operations services to serve the electrical demand and energy requirements of its end-use customers.

[4] Several new transmission projects within the PJM portion of the RFC region and planned for service in the next five to fifteen years, were not included in the data submitted for this assessment. These proposed long-lead-time projects are currently in the PJM Siting Feasibility Study stage to evaluate which projects or portions thereof will move forward.

diversity; in some situations, this can lead to supply shortages and involuntary customer interruptions.

- With a few exceptions, the present transmission planning horizon is five years or less. Proposed solutions tend to address short term problems without looking to longer lead time facility requirements.

- Obstacles to the siting and certification of new transmission in the U.S. may be eased and transmission development enhanced by several actions: U.S. Department of Energy (DOE) designation of National Interest Electric Transmission Corridors (NIETC) and the associated FERC backstop siting authority; DOE designation of multipurpose energy corridors; and DOE serving as the lead agency for federal authorizations, permits, and approvals for interstate transmission projects.

- Although there has been a recent upturn in planned transmission investment in several regions, growth in peak demand and generation additions will pose new challenges.

- FERC's recently issued transmission pricing rule offers a wide range of incentives and pricing reforms to stimulate needed investment in new transmission facilities to projects that qualify in both RTO/ISO and non-RTO/ISO regions.

- Bulk power system reliability and adequacy depends on close coordination of generation and transmission planning and demand response programs.

Actions Needed:

- Based on the congestion study released on August 8, 2006, the U.S. DOE, in conjunction with transmission owners and planning authorities, needs to complete the designation of NIETCs.

- RTOs and transmission owners need to address other areas of congestion and emergency transfer capability that could impact reliability, and create a long-term vision for a high capacity grid system.

- State and federal government agencies in the United States. need to work on removing obstacles to expedited siting and certification of transmission lines independent of the recommendations by DOE.

- Canadian federal and provincial government agencies need to work diligently to remove similar obstacles in Canada.

- Transmission owners, planning authorities, and other stakeholders need to engage in long-term, robust, and comprehensive regional planning for transmission infrastructure, including infrastructure needed for new sources of generation.

- Federal, state, and provincial regulators need to reduce regulatory barriers and encourage investment in transmission infrastructure improvements.

- NERC will expedite the development of its new reliability standard that will establish requirements for assessing the performance of planned bulk power transmission systems and the requirements for documenting plans to remedy reliability inadequacies identified in the process of conducting such assessments.

Fuel Supply and Delivery for Electric Generation Important to Reliability

- The adequacy of electricity supplies depends, in part, on the adequacy of fuel supply and delivery systems, not just the installed capacity of generators.

- Gas-fired generating capacity additions are projected to account for almost half of the resource additions over the 2006–2015 period.

- Dependence on natural gas for electric generation is projected to increase in ERCOT, FRCC, the U.S. portions of MRO, NPCC, and WECC.

- The supply and delivery of gas to electric generators can be disrupted when electric generation demands for gas coincide with high gas demands for other customers. In some cases, even firm gas contracts for electric generation can be curtailed in favor of residential heating needs during extreme cold weather.

- Strengthening fuel delivery infrastructures and firming up gas supply and delivery contracts will reduce the potential for shortages in electricity supplies due to fuel disruptions.

- Coal delivery infrastructure was an issue in 2005 and early 2006, but the situation is improving.

Actions Needed:

- Electric utilities, resource planning authorities, and resource providers need to evaluate the reliability of fuel supply and delivery systems when determining electricity supply adequacy.

- Entities that purchase fuel for electric generators need to review and strengthen fuel supply and delivery contracts to ensure that fuel disruptions do not limit generator operation during critical electric supply situations.

- System operators and planners need to evaluate the consequences of unexpected fuel transportation contingencies on the reliability and adequacy of the bulk power system.

- Communications and emergency operating procedures between electric system operators and gas pipeline operators need to be in place to address extreme cold weather events.

- Federal, state, and provincial agencies, along with fuel supply and delivery industries, need to evaluate the adequacy of these critical infrastructures for supporting an adequate electricity supply system.

- NERC and regional reliability organizations will include in their regional reliability assessment programs a review of the impact of any fuel transportation infrastructure interruption that could adversely impact electric system reliability.

Aging Workforce a Challenge to Future Reliability

- The reliability of the North American electric utility grid is dependent on the accumulated experience and technical expertise of those who design and operate the system.

- As the rapidly aging workforce leaves the industry over the next five to ten years, the challenge to the electric utility industry will be to fill this void.

Actions Needed:

- Electric utilities need to identify key personnel approaching retirement and establish mentoring programs to impart the experience realized by these individuals.

- Electric utilities need to reassess compensation and benefits packages to attempt to retain aging personnel, either on a full-time or part-time basis.

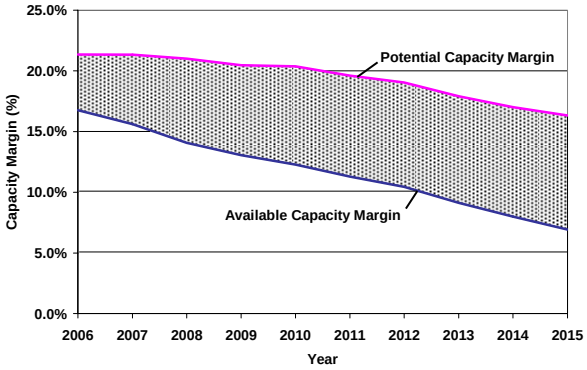
- The electric utility industry as a whole needs to establish cooperative programs with academia to reinvigorate the power engineering education in North America.

ASSESSMENT SUMMARY

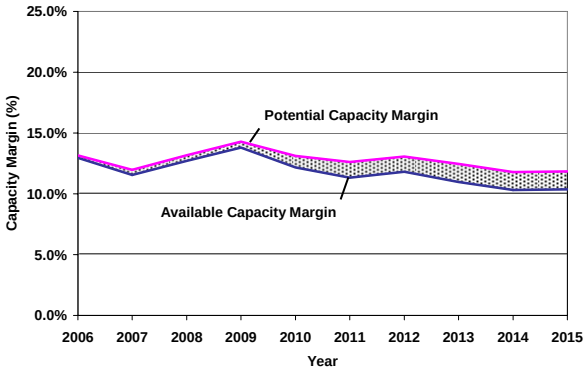
Action Needed to Ensure Resource Adequacy Over the 2006–2015 Period

Available capacity margins in the U.S. and Canada are projected to decline over the 2006–2015 period. Margins vary from region to region, as does the amount of *uncommitted resources* reported.

Capacity margins in United States decline throughout ten-year period. Uncommitted resources offer significant potential.



Capacity margins in Canada steady in short term; decline in long term.



Capacity Margin — 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.

Available Capacity Margin — The difference between ***committed*** capacity resources and peak demand, expressed as a percentage of capacity resources.

Potential Capacity Margin — The difference between ***committed*** plus ***uncommitted*** capacity resources and peak demand, expressed as a percentage of capacity resources.

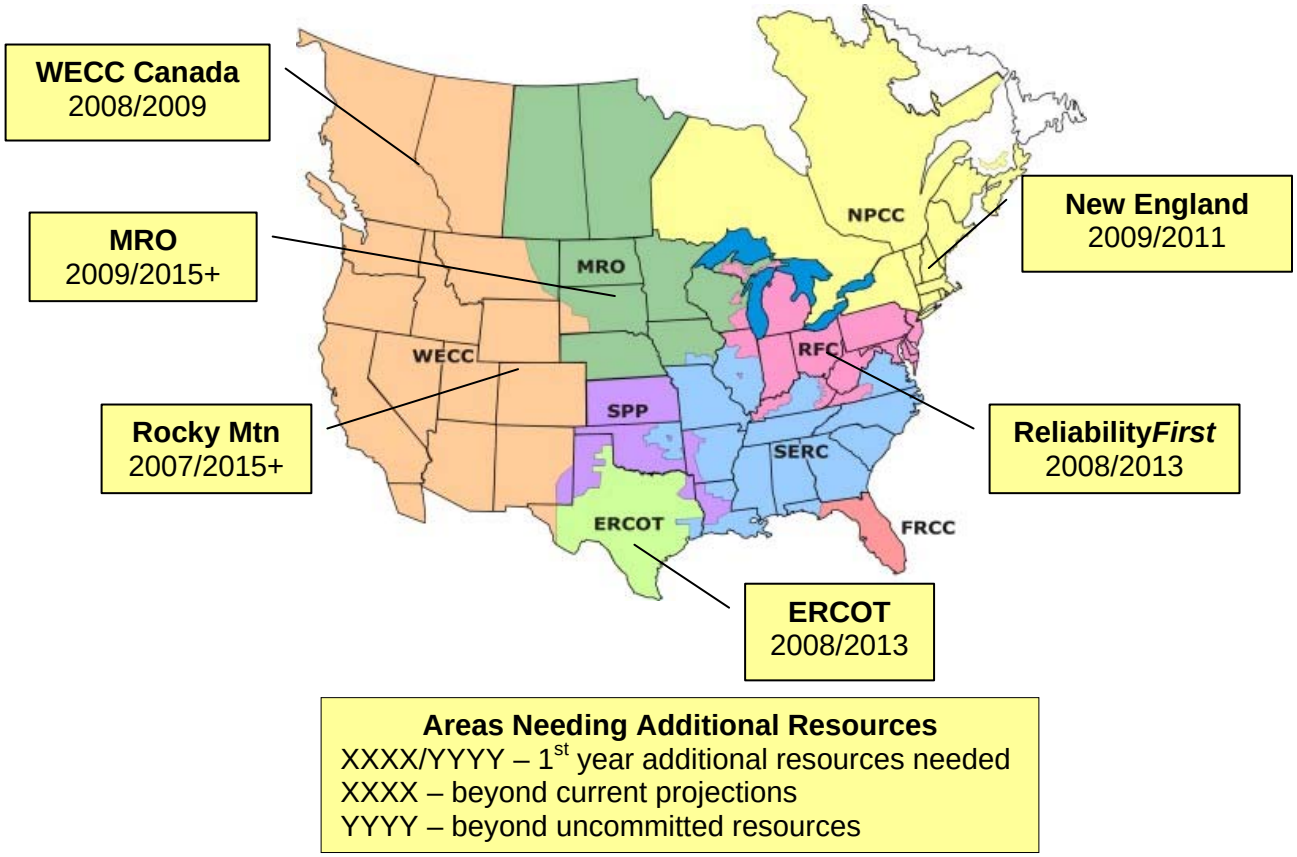
Committed Capacity Resources — Generating capacity resources that are existing, under construction, or planned that are considered available, deliverable, and committed to serve demand, plus the net of capacity purchases and sales.

Uncommitted Capacity Resources — Capacity resources that 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 margins drop below minimum target levels in ERCOT, MRO, New England[5], RFC, and Rocky Mountain and Canada areas of WECC in the next 2–3 years, with many other areas reaching minimum levels later in the ten-year period. However, all regions have some additional resources potentially available in the form of *uncommitted resources* that exist, are under construction, or are in the planning stage, which offer the potential to meet minimum target levels. Actions needed to make these resources available when required include returning "mothballed" units to active service, entering into power purchase agreements for existing or new resources, upgrading transmission to provide access to resources that would not otherwise be deliverable, and developing and bringing into service projects that are in generator interconnection queues.

Electricity Supply Margins
Projected to Fall Below Minimum Target Levels
in Some Areas of North America in Next 2–3 Years



For example, in ERCOT, available capacity margins will drop below the 11 percent minimum target level by 2008. The ERCOT potential capacity margins, which include the effects of uncommitted resources, remain above the required minimum through 2013. In the case of ERCOT, the uncommitted resources comprise generators that are in "mothballed" status, but which could be returned to active service if needed.

[5] The FERC recently approved a forward capacity market for ISO New England, is expected to result in additional resources in the next three years.

In some cases, areas that require additional resources to meet minimum target levels can purchase those resources from neighboring regions or subregions.

Even if additional resources are added, the possibility remains that above average resource unavailability, coupled with high demands caused by extreme weather, could create localized supply problems.

Reliability Will Depend on Close Coordination of Generation and Transmission Planning and Construction

Electric utilities forecast demand to increase over the next ten years by 19 percent (141,000 MW) in the U.S. and 13 percent (9,500 MW) in Canada, but project committed resources to increase by only 6 percent (57,000 MW) in the U.S. and by 9 percent (9,000 MW) in Canada. Given the short lead-time for developing some types of generation, this difference could be offset by assignment or development of capacity that has not yet been committed or announced.

More than 9,000 miles of new transmission (230 kV and above) are proposed to be added through 2010, with a total of about 12,873 miles added over the 2006–2015 time frame[6]. The increase represents a 6.1 percent increase in the total miles of installed extra high voltage (EHV) transmission lines (230 kV and above) in North America over the 2006–2015 assessment period. Furthermore, upgrading or replacing existing lower capacity transmission lines also increases the capacity and reliability of the existing transmission network, but does not increase the reported miles of transmission lines.

North American transmission systems are expected to meet reliability requirements in the near term. However, as customer demand increases and transmission systems experience increased power transfers, portions of these systems will be operated at or near their reliability limits more of the time. Under these conditions, coincident unavailability of generating units, transmission lines, or transformers, while improbable, can degrade bulk power system reliability.

Even though NERC expects the transmission systems to be operated reliably, some portions of the grid will not be able to deliver available resources to areas needing additional resources to meet minimum target levels for adequacy, or be able to support all desired electricity market transactions. Some well-known transmission constraints are recurring, while new constraints appear as electricity flow patterns change.

In the long term, reliable transmission will depend upon the close coordination of generation and transmission planning and construction and the adoption of longer term planning horizons (ten or more years). This coordination activity must now be accomplished through different means than in the past and involves coordination among many different market participants. A combination of market signals and regulatory decisions will dictate the location and timing of generating capacity additions, and also influence the siting and construction of new transmission facilities.

Fuel Supply Will be a Bigger Factor in Meeting Capacity Margins

Most regions do not anticipate any long-term problems with fuel supplies for the 2006–2015 assessment period. However, if short-term interruptions of supply occur, affected generators will need to implement contingency plans to manage the operation of their facilities. For example, beginning in 2005 and over the course of 2006, deliveries of western coal from the Powder River Basin (PRB) were curtailed due to rail track maintenance. These deliveries are improving but are not yet meeting all desired delivery

[6] Several new transmission projects planned for service in the next five to fifteen years within the PJM portion of the RFC region were not included in the data submitted for this assessment. These proposed long-lead-time projects are currently in the PJM Siting Feasibility Study stage to evaluate which projects or portions thereof will move forward.

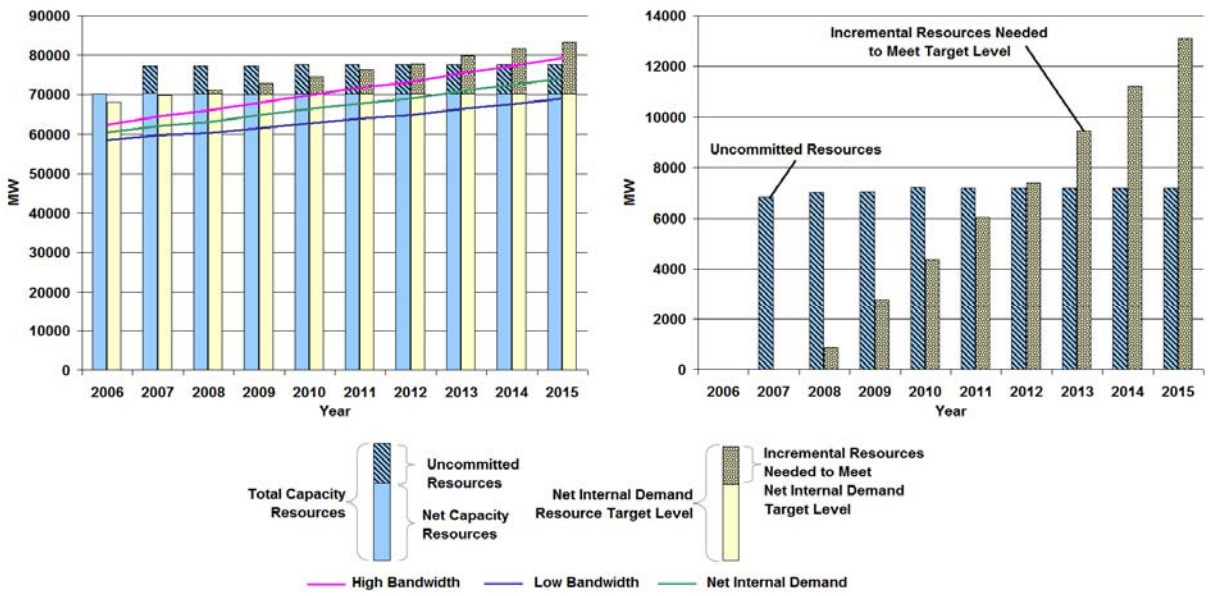
requests. Close review of natural gas supply and delivery issues will also be required in some regions due to the increasing reliance on natural gas for electric generation. This issue becomes particularly critical during the winter or following major storms or hurricanes as experienced during the winter of 2005/2006 following hurricanes Katrina and Rita.

Hydroelectric resources will be affected by the amount of precipitation each year, which cannot be accurately predicted very far into the future. This long-term assessment relies on historical average rainfall levels when considering the availability of hydroelectric resources. These assumptions are addressed more specifically during seasonal assessments.

Regional Assessment Highlights

ERCOT

The Electric Reliability Council of Texas, Inc. (ERCOT) is projecting about 2,000 MW less installed capacity over the assessment period than in last year's assessment due to wind generation deratings from last year's assessment and additional unit mothballing. Along with an increased load forecast, this results in lower capacity margins than last year's assessment. The assessment indicates capacity margins should remain close to, but above, the 11 percent target until 2008 (compared to 2010 in last year's assessment). However, approximately 7,000 MW of existing mothballed generating capacity is not included as available capacity that could potentially be brought back into service in a short time frame. In order to meet the capacity margin target in 2008, ERCOT may need to commit some of the mothballed generation.



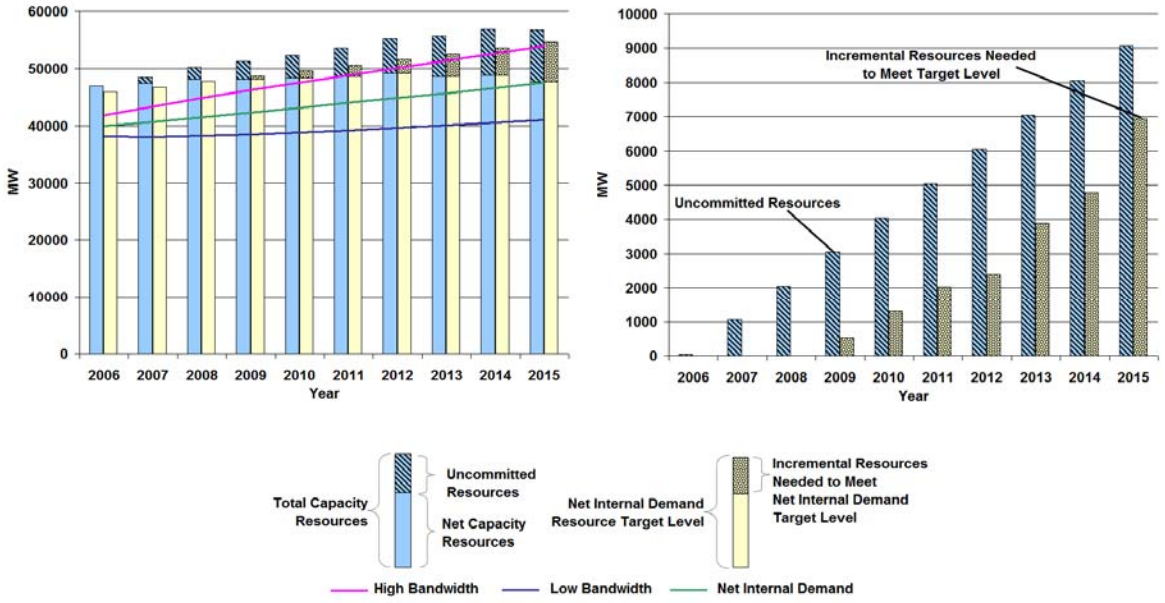
Approximately 6,100 MW of publicly announced new generation is also scheduled to come on-line between 2006 and 2011, without signed interconnection agreements ,that is not included in ERCOT's capacity forecast. Many of these facilities are coal-fired and will not be available until 2009–2010. The Public Utility Commission of Texas is in the process of considering rules to maintain capacity adequacy in ERCOT going forward.

FRCC

The Florida Reliability Coordinating Council (FRCC) expects to have adequate generating capacity reserves and for the transmission system to operate reliably throughout 2006–2015. However, the transmission lines between southwestern central Florida generation and the greater Orlando load area will continue to be heavily loaded and will require extensive operational procedures. Permanent solutions are under review to resolve these deficiencies with new transmission projects. Based on the committed projects and expected generation dispatch, it is expected that these operational procedures will continue in this area until 2010. Remedial operation strategies have been developed to address these conditions and will continue to be evaluated to ensure system reliability. Utilities have announced plans for 5,524 MW of new coal-fired plants, which will increase fuel diversity.

MRO

Sufficient generating capacity is expected within the entire Midwest Reliability Organization (MRO) to meet its reserve capacity obligations through 2009. The MRO-Canada region has adequate generating capability throughout the assessment period. Currently, planned capacity reported in the MRO-U.S. region is below MRO requirements for reserve capacity obligations from 2010–2015. However, the MRO does not expect any capacity deficits to occur during the assessment period because capacity margins are expected to be higher than reported based on significant new generation identified in the regional ten-year plan for the period of 2004–2013.



Through the 2015 planning horizon, the MRO expects its transmission system to perform adequately assuming proposed reinforcements are completed on schedule. Continued power market activity will continue to fully utilize the capability of the system, which may not meet all market needs.

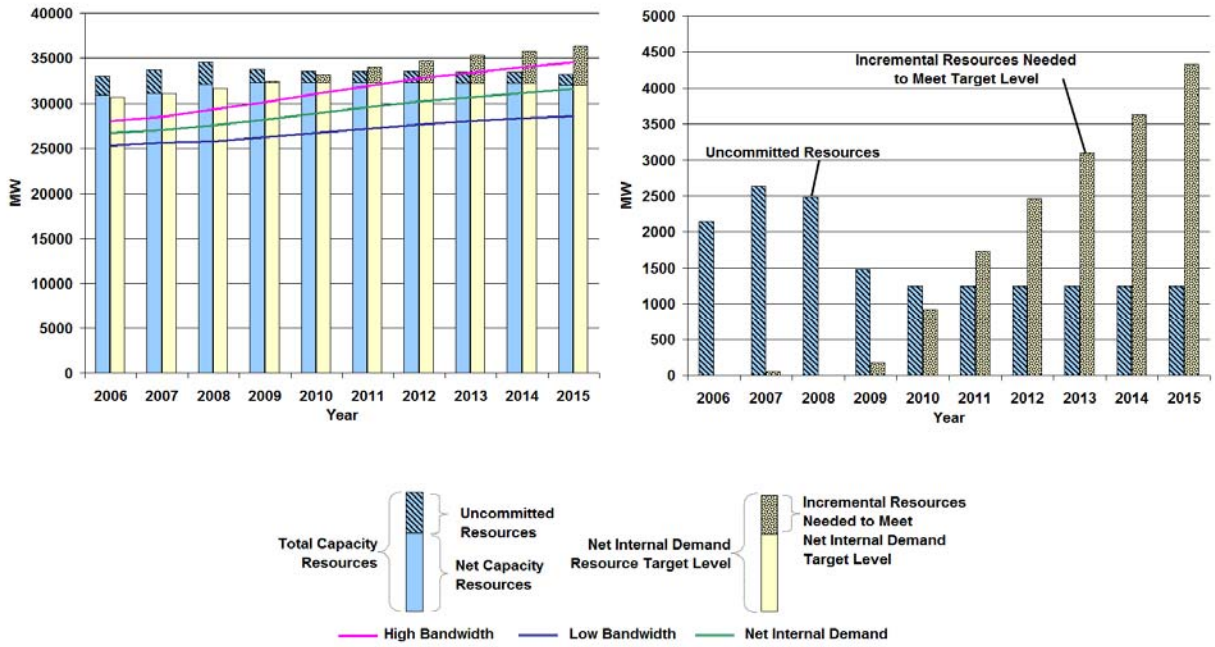
NPCC

New England

Installed reserve margins will be declining throughout the study period from a high of 15 percent in 2008 to almost 0 percent in 2015. The installed reserve margins reflect firm capacity purchases of approximately 400 MW per year through 2012, approximately 330 MW purchase in 2013–2014, and approximately 110 MW in 2015. There are no generating unit retirements assumed throughout the study period and new generation totaling approximately 1,390 MW (capabilities include projects that have received proposed plan approval) is assumed to commercialize by the end of 2009.

With respect to the regional requirement, ISO New England anticipates that New England will meet the NPCC resource adequacy criterion of one-day-in-ten-years loss-of-load expectation through 2008 assuming forecasted loads and capacity materialize and 2,000 MW of tie reliability benefits are available. This is made up of 600 MW from New York, 1,200 MW from Hydro Québec, and 200 MW from New Brunswick. Existing transfer capability study results indicate that there is sufficient transfer capability with surrounding areas to receive this assistance when needed. New capacity will be needed beyond that year in order to meet the reliability criterion. This assessment is based on estimated requirements calculated in the 2006 Regional System Plan.

To meet NPCC criteria, and assuming 2,000 MW of tie reliability benefits are available from neighboring control areas, approximately 170 MW are needed in 2009, increasing annually and requiring a total of 4,300 MW by 2015.



New York

Given current demand projections, New York would need the addition of 4,030 MW of new resources in order to meet a projected 18 percent level through 2015. This projection assumes the continuation of the current level of external purchases of approximately 2,500 MW and the continuation of special case resources of approximately 1,080 MW. It is anticipated that the resources necessary to meet this projected requirement would be procured through the NYISO ICAP market. Currently, new capacity totaling 2,940 MW is under construction in New York. The generation currently under construction in conjunction with the approximately 2,500 MW of allowable external purchases will be sufficient for New York to meet an 18 percent reserve margin through 2015 even if no new projects are proposed.

Ontario

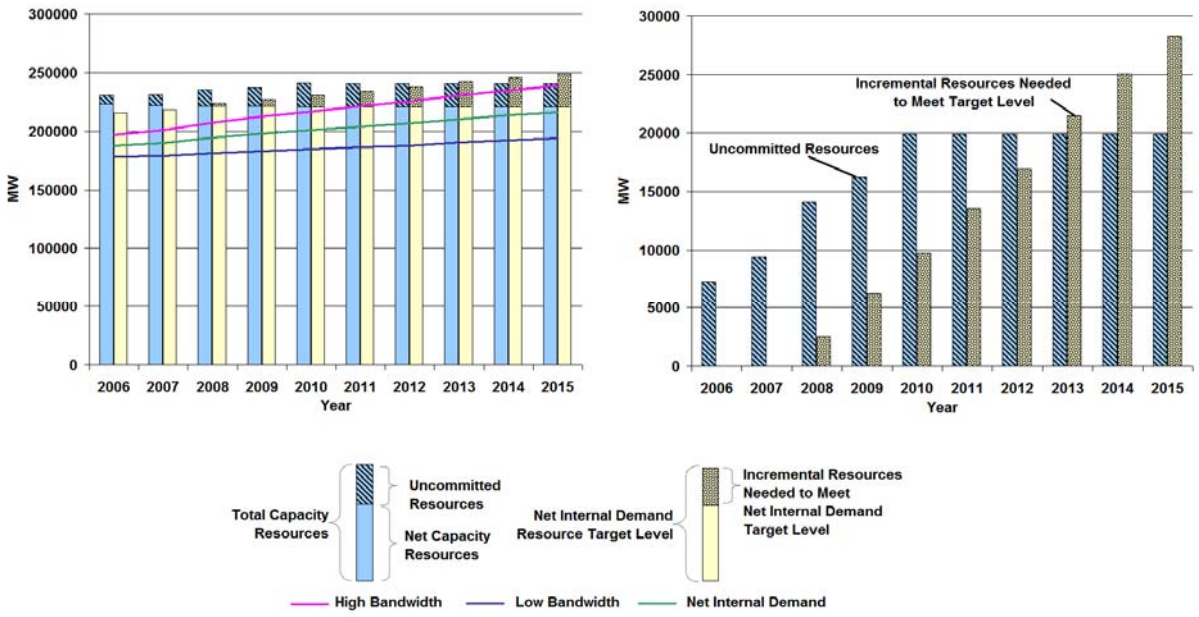
Since last summer, more than 600 MW of new supply has been added to the Ontario power system, which has improved Ontario's supply outlook in the short term. Under median demand growth assumptions, resources that are currently available within Ontario, together with the contracted new generation and imports, are sufficient to meet the NPCC resource adequacy criterion from 2006–2015.

Québec

In the *2005 Québec Area Triennial Review of Resource Adequacy*, Québec demonstrated that the installed reserve margin requirement was about 10 percent over the annual peak load to comply with the NPCC adequacy criterion. For the whole period, the expected installed reserve margin will be over this percentage. Even in the case of a high load scenario, Québec still meets the NPCC resource adequacy criterion (lost of load expectation less than 0.1 day/year).

RFC

The Reliability*First* Corporation (RFC) region is expected to have sufficient resources to satisfy a 15 percent reserve margin through at least 2007. Proposed capacity additions and existing capacity that is undeliverable, uncommitted, or energy-only resources, could satisfy the 15 percent reserve margin through 2012, if the transmission system is capable of fully delivering those resources. Additional capacity resources will still be needed beyond 2012 to maintain a 15 percent reserve margin. No commitments to resource development beyond 2011 are known at this time.



SERC

Capacity resources in SERC are expected to be adequate to reliably supply the forecast firm peak demand and energy requirements throughout the long-term assessment period. Significant generation development has occurred in the SERC region during the past few years, resulting in thousands of MW of uncommitted generating capacity. Some of this generation can be made available as short-term nonfirm or potential future resources to SERC members and others.

SPP

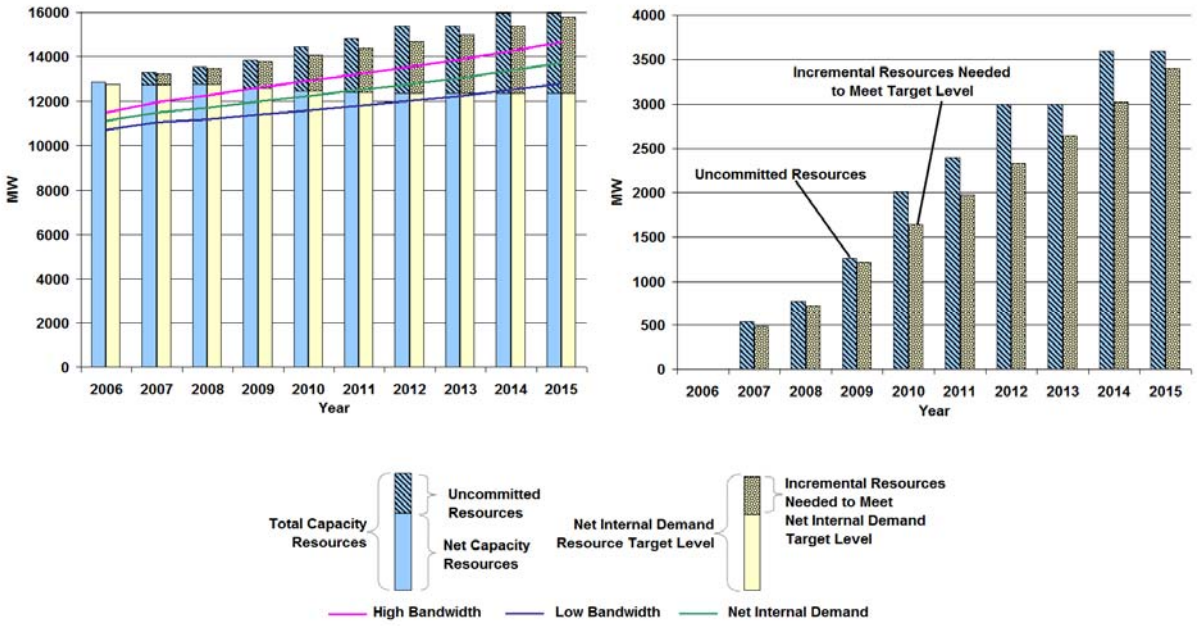
Southwest Power Pool (SPP) anticipates consistent growth in demand and energy consumption over the next ten years. Adequate generation capacity is forecasted in SPP to be available over the planning horizon to meet native network load needs with committed generation resources meeting minimum capacity margins.

Expansion of the existing transmission system to address the reliability and economic needs of the market is a top priority for SPP. SPP is in the process of implementing several initiatives that will result in transmission expansion and better utilization of the existing assets in the footprint. The existing bulk power system is expected to reliably serve the needs of native network load for the short-term while incremental system flows from commercial transmission reservations will most likely utilize any remaining transmission capacity.

WECC

Due to a slight decrease in existing generating capacity and a significant decrease in reported generation additions, capacity margins for the Western Electricity Coordinating Council (WECC) are reported as declining throughout the ten-year assessment period. The capacity margin declines occur in multiple subregions. WECC's *2006 Power Supply Assessment Report* (PSA) indicates that summer electricity supply shortages relative to study planning margins could occur as early as 2009 and winter electricity supply shortages could occur as early as 2008–2009 in Canada, assuming normal weather, adverse hydroelectric conditions, and no resource additions beyond those presently under active construction with expected in-service dates prior to July 2007 (or July 2008 if coal-fired).

The Rocky Mountain Power Area (RMPA) summer 2007 capacity margin is 9.8 percent without uncommitted resources and 13.2 percent with uncommitted resources. By the summer of 2011, those margins become -0.8 percent and 15.5 percent, respectively. A significant portion of the expected uncommitted resources has received state utility commission approval and is under active development.



The WECC-Canada winter 2008–2009 capacity margin is 5.1 percent without uncommitted resources and 7.1 percent with uncommitted resources. By the winter of 2011, those margins become -1.1 percent and 5.1 percent, respectively.

The PSA reports that by 2009, summer transfer capability limitations between the winter peaking northern portion and summer peaking southern portion of WECC result in a 1,000 MW resource shortfall. The southern portion resource needs increase to roughly 20,000 MW by 2015, even though the northern portion is capacity surplus throughout the period. Although the transmission limitations represented in the PSA analysis are conservative, they are not unreasonable and the report clearly establishes that WECC has insufficient transmission to fully utilize seasonal capacity/demand diversity within the Western Interconnection.

The PSA report is available at: (http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=getit&lid=2330). Plans have been announced for 5,951 miles of 230-, 345- and 500-kV transmission line construction and upgrades during 2006–2015. These additions will not significantly reduce the northwest-to-southwest transfer capability constraint.

Transmission rated at 230 kV and above increased by about 140 miles in 2005. Proposed transmission facility additions reported for 2006–2015 include 2,276 miles of 230-kV lines, 1,075 miles of 345-kV lines, and 2,600 miles of 500-kV lines. Depending on transmission and resource addition in-service dates and locations, the transmission system may be adequate to satisfy firm transmission interconnection requirements but may not be adequate to allow full utilization of capacity/demand diversity throughout 2006–2015.

Emerging Reliability and Adequacy Issues

Significant Transmission Expansion Project Plans

Over the course of the last couple of years, several large scale transmission expansion projects have been proposed by a number of entities across North America. The main objectives of these projects include:

- eliminating regional transmission system congestion,
- promoting fuel diversity, and
- access to renewable resources.

These projects typically involve large scale transmission lines connecting generation-rich areas to areas that need those resources. Some of these projects are proposed within the footprint of established RTOs with established transmission expansion processes, and others are proposed in regions not operated by RTOs or ISOs making the approval of project need unique to each project. Although the typical attribute of these projects is that they are intended to enhance the economic efficiency of the bulk power system or to access renewables, they will also have a reliability benefit by increasing operational flexibility.

While not all inclusive, the following is a listing of examples of the type of projects discussed in this section:

Project Name	Proposed Capacity	Description
I-765	5000 MW	Line from West Virginia to New Jersey to access lower cost coal and gas resources
Frontier Line	6,000 MW	Line from Wyoming to Utah, Nevada, Arizona and California to access clean coal and wind resources
Transwest Express	3,000 MW	Line from Wyoming to Arizona to access clean coal and wind resources
Northern Lights	3,000 MW	Line to access tar sands in Alberta
Sea Breeze	1,600 MW	Undersea dc cable from northern Oregon to northern California to access renewable resources
Neptune	790 MW	A merchant HVdc line between Sayreville (New Jersey) and Newbridge Road (New York) substations
Clear Springs–Salado Project	3,300 MW	Line from economic generation in central Texas through several load centers to the north
Houston Area Constraint Mitigation Project	3,600 MW	Several new lines, line upgrades, and a switching station that increase import capability into the Houston area
Paris–Anna Line	1,600 MW	Line from economic generation in the N.E. part of Texas into the Dallas-Fort Worth metroplex
Jacksboro–West Denton Line	1,600 MW	Line that increase Dallas-Fort Worth access to wind resources

These large scale transmission projects have the potential to profoundly change the operations and planning of the transmission system in these areas. The actual development of these projects have the potential to significantly impact overall electric system reliability in a variety of ways. The potential system reliability benefits include increased generation fuel diversity reducing reliance on any one fuel to meet load requirements and reduced congestion and the associated simplification of operations.

Other impacts of these projects would be increased reliance on remote generation sources replacing less economical or less desirable generation located closer to the load center. Issues associated with replacement of generation near load centers such as reactive power and voltage support can be addressed through careful system planning. To the extent the new transmission expansion leads to integration of increased renewable resources, operational and reserve requirement issues associated with intermittent and energy limited resources discussed in the renewable resources section will also need to be addressed to assure continued system reliability.

Demand Diversity and Transmission Constraints

Peak demands often occur during different times and different seasons for the load-serving entities (LSEs) within geographically large regions. This seasonal demand diversity may be quite significant between summer peaking LSE and winter peaking LSE. In general, resource providers typically attempt to maximize plant utilization by exporting off-peak season surplus capacity among the subregions. Under normal weather conditions, this weather diversity also allows an area experiencing extreme weather to call on neighboring areas for support.

The resource data presented in this report reflects appropriate capacity reductions in cases where radially connected generation or small resource-surplus areas have limited export capability (a.k.a., "bottled capacity"). However, the data reflects primarily the expected exports based on historical diversity exchanges, excluding possible capability reductions due to local off peak load growth consuming the surplus, or potential transmission constrained utilization of the seasonal surplus capacity that may occur in the future.

For example, a very widespread heat wave may result in multiple areas experiencing simultaneous high peak demands, diminishing emergency support capability assumed available based on the historical diversity. In addition, the assumptions that past diversity exchanges will continue to occur in the future may be impacted as off-peak surpluses are being absorbed within the subregion's own growth.

Inter- and intra-region transmission constraints and increased utilizations may also reduce the ability to export all of the seasonal-surplus capacity. Addressing such transmission constraints is often problematic. For instance, hydroelectric generation may vary dramatically from year to year due to varying amounts of precipitation. As a consequence, transmission constraints can be quite significant some years and of little consequence other years.

Transmission Expansion Difficulties

Regulatory and licensing issues continue to push out the in-service dates of needed transmission projects. While most agree that new transmission lines can improve system reliability and enhance economic transfers of energy, siting of lines still runs into the same roadblocks as years past. These delays also can increase the cost significantly.

"Not In My Back Yard" (NIMBY) issues apply to many industries besides the electric power industry, but the higher public exposure to long transmission lines with wide right-of-ways seems to cause the most consternation among the public. Concerns about the health aspects of living next to a transmission line still linger.

Recovery of the extreme high cost of acquiring property and building a new line can take years or may even be uncertain. The investment in construction of a new line is considerable. In some areas, recovery of these costs is left up to case by case negotiations between the builder and, possibly multiple state utility commissions. This can be very discouraging on the builder's part. Other areas may have structured cost recovery mechanisms in place but full recovery may take several decades.

Acquiring right-of-way property can be influenced by several aspects including land prices, environmentally sensitive areas, and NIMBY issues. Land prices are increasing along with the quickly rising cost of housing. In some areas, land price inflation is averaging three or four times the general inflation rate. Some environmental groups are well organized with extremely good legal representation. All legal options to stop transmission line development are usually utilized.

Many developers are concerned about quicker development of generation in resource limited areas. Average time to plan and build a transmission line is considerably longer than the time it takes to permit and build some generation plants. The need to alleviate a congested path by building a new transmission line into a resource limited area may be made unnecessary by the addition of generation in that area.

This problem has no easy solution. Outreach and education efforts to enhance awareness of need for more transmission will help to enlighten local governments and some individuals. The culmination of the federal government helping with siting at the national level may streamline some of the possible delays. Some have even suggested sharing transmission line revenues with land owners near the right-of-ways. Integrated large scale resource planning can referee the transmission/generation fight with an overall plan that will utilize the most economic solution to the reliability problems encountered.

The Energy Policy Act of 2005 contains several provisions that could help enhance transmission siting such as DOE designation of National Interest Electric Transmission Corridors and associated FERC backstop siting authority; DOE designation of multipurpose energy corridors; and DOE coordination as lead agency of all necessary federal authorizations, permits and approvals for interstate transmission projects.

Fuels

Resource adequacy is measured by the capacity in MW of the physical "iron in the ground" represented by the generating plants, both existing and planned. However, an adequate supply of reliable electric resources to the North American electric grid is equally dependent on readily available fuel supported by a secure transportation infrastructure to deliver the fuel to the generating facility. An important element is diversity of fuel. In recent years, the electric industry has witnessed numerous events that can potentially diminish the supply of any given fuel:

- Hurricanes in the Gulf of Mexico in the summer of 2005 threatened the supply of off-shore natural gas to the United States.
- Extended droughts in the west reduced the available energy of several major hydroelectric sites in the late 1990s.
- Tensions in the Middle East continue to result in dramatic fluctuation in the price for fuel oil and could ultimately lead to major supply interruptions.
- In 2003, the political unrest in Venezuela interrupted the only production of orimulsion fuel.
- Shutting down mines due to safety issues.
- Curtailments of rail delivered/barge delivered coal.
- Short-term fuel acquisition problems driven by global markets.

The security of the supply of off-shore oil may, in future years, be dependent on the political stability of those countries exporting the majority of the world's oil, many of which are currently experiencing

internal turmoil. This also includes the import of liquefied natural gas (LNG), which, although a natural gas product produced by the extreme cooling of natural gas into its liquid state, is supplied by many of the same regions of the world on which North America is dependent for its oil supply. Thus the uncertainty of both the price and availability of imported oil makes it increasingly unreliable as a utility fuel in the years ahead.

Because it is efficient and clean burning, natural gas has become the preferred fuel in North America for new generation additions, and its consumption by the electric utility industry is increasing rapidly. In addition, natural gas is also a prevalent fuel for home heating in many parts of North America, competing with the electric utility for gas supply at peak times. With this continuing growth in gas usage by the electricity sector, the adequacy and security of the natural gas supply and its infrastructure will become ever more critical to the reliability of electric supply. As a result, some utilities are looking towards clean coal-fired generation technologies for future capacity additions. Appropriate cost-recovery mechanisms will be needed to provide incentives for the construction of long-lead-time coal facilities.

Renewable energy and nuclear power are being pursued as an alternative to the ever increasing consumption of fossil-fuels in North America, with several states and provinces in North America having established standards requiring that a minimum percentage of energy consumed be derived from renewable resources. At the federal level within the United States, the Energy Policy Act of 2005:

- Encourages the renewed construction of nuclear generating plants;
- Provides loan guarantees for innovative technology that does not yield greenhouse gases as a combustion byproduct;
- Encourages increased research in clean coal burning technology;
- Requires the staged increase in the dilution of gasoline with ethanol;
- Provides subsidies for wind generation; and
- Encourages research into such renewal programs as tidal energy, biomass fuel, etc.

In the near term, renewable energy will largely be supplied by existing hydroelectric facilities and the growing numbers of wind generators entering the grid.

Although no new nuclear capacity has been constructed in about 30 years in the United States, the Energy Policy Act of 2005 hopes to provide the economic incentives to resume construction, and a number of applications for new units have been announced.

Aging Infrastructure

The North American transmission system has evolved over the last century during periods of rapid growth from the 1950s through the 1970s paralleling the technological advancements in generation. The transmission facilities installed through the 1970s are reaching the end of their projected useful life. These facilities will need to be either replaced or repaired to maintain grid reliability.

Over the past decades, the vast majority of transmission investment was directed towards constructing new facilities to meet customer load demands and comparatively little capital investment was expended for the refurbishment of the existing facilities. The aging transmission system infrastructure has many challenges such as: the availability of spare parts; the obsolesce of older equipment; the ability to maintain equipment due to outage scheduling restrictions; and the aging of the work force and lost knowledge due to personnel retirements.

The North American transmission owners must take a more proactive approach going forward in replacing obsolete and unreliable equipment including transmission lines. Chronological age is not the only condition that should be used to determine when equipment should be replaced. Potential for

increased failure rates should be evaluated. These considerations should consider the diversity of equipment technologies and installation dates. However, implementation of any replacement strategy and in-depth training programs require additional capital investment, engineering and design resources, and construction labor resources, all of which are in relatively short supply.

Renewable Resources

Renewable resources will become an increasing portion of total generation resources in the future. Generation from wind, solar, biomass, geothermal, hydro, and to a lesser extent, wave/tidal, landfill gas, and municipal or biomass-based waste are generally considered renewable sources. Nearly 14,000 MW are projected to be added over the next ten years throughout North America.

Currently, a total of 21 states and the District of Columbia have adopted renewable portfolio standards (RPS) for the purchase of energy. Generally, the RPS obligation is imposed on load-serving entities and usually requires them to obtain a portion of their electricity supply from renewable resources; in some states as much as 25 percent. Wind generation is expected to provide the bulk of the energy required to meet requirements for additional generation from renewable sources. However, wind generation is often located in remote areas, which requires new transmission construction to deliver its energy to load. Because wind and some other renewable sources of electric power are intermittent in nature, actual generating capacity available at times of peak demand is less predictable than it is for capacity produced from more traditional technologies. Another characteristic of renewable sources is that typically the actual electricity produced in relation to the available capacity is relatively small. Although a large amount of capacity based on maximum output may be planned, these resources will be "energy-limited" and produce a relatively low level of MW-hours compared to their maximum capacity.

Intermittent and energy-limited renewable resources require that sufficient dispatchable resources and transmission capacity be available to assure system resource adequacy and operating security at all times. One way to take this into account in assessing a region's resource adequacy is to discount the total installed capacity from renewable sources to a level that reflects their expected operating capacity at the time of highest system demand. The appropriate level of assumed reduction is very much dependent upon regional conditions and the mix of renewable energy technologies. These characteristics might require the installation of additional thermal generation to ensure the ability to reliably serve load at the time of system peak.

Further, renewable resources have some unique characteristics that need to be analyzed to determine their ability to operate within the capacity of local transmission facilities. Specific characteristics include reactive power capability, voltage regulation, and low-voltage ride-through capability, which allows generation to remain connected to the bulk system under low-voltage conditions. These characteristics have historically been problematic for wind generation. However, as amounts of wind generation are increasing, the manufacturers are improving the capabilities of the equipment being installed. In the past year, FERC has adopted standard interconnection requirements that apply to new wind generation capacity. These new requirements should help assure that new renewable generation being added does not degrade system reliability.

Aging Work Force

While the post-war population surge has provided a young and well trained workforce for over 50 years, the baby boom generation is now entering retirement age. By 2030, the youngest baby boomers will have reached the retirement age of 66; at that point it is projected that almost 20 percent of the U. S. population will be 65 years of age or older[7]. Because of the declining birth rates since the 1960s, the workplace will not be able to replace the older baby boomer at the rate at which he or she will leave the work force.

[7] Lockwood, Nancy R.; December, 2003; The Aging Workforce; Society for Human Resource Management.

The loss of skilled and experienced technical talent is much more acute in the electric utility industry. According to a Hay Group study, 40 percent of senior electrical engineers and 43 percent of shift supervisors will be eligible for retirement by 2009. That study also found more than two-thirds of utility companies surveyed have no succession plan for supervisors and 44 percent have no plans for vice presidents. Not only does the industry not have enough professionals and managers, but the skilled labor force will be severely affected. Trying to get journeyman electricians and linemen will be more difficult than hiring the professional workforce.

At the same time, the demand for engineers with power background and other utility professionals has increased due to the advent of independent transmission companies, regional transmission organizations, and various markets. This caused the transmission dependent users, independent power producers, and other wholesale entities to increase their professional staff, particularly those with transmission planning expertise.

Aggravating the problem of sustaining the essential technical knowledge is the dwindling numbers of students in the power engineering programs of most universities. Currently, the electric power engineering programs within the United States graduate about 500 engineers per year; in the 1980s, this number approached 2,000.

The reliability of the North American electric utility grid is dependent on the accumulated experience and technical expertise of those who design and operate the system. As the rapidly aging workforce leaves the industry over the next five to ten years, the challenge to the electric utility industry will be to fill this void. Individual utilities are adopting innovative measures to bridge this emerging knowledge gap that include:

- Identifying key personnel approaching retirement and establishing mentoring programs to impart the experience realized by these individuals;
- Reassessing compensation and benefits packages to attempt to retain aging personnel, either on a full-time or part-time basis; and
- Hiring engineers and other utility professionals from outside the United States.

For those utilities where corporate consolidation and mergers occurred, the need to replace its aging workforce may not be as severe because it takes fewer people to do the same work after consolidation or merger. The electric utility industry as a whole has not, however, established the needed cooperative programs with academia to reinvigorate the power engineering education in North America.

Green House Gas Emissions

The long-term implications of greenhouse gas (GHG) emissions policies on the adequacy of future electricity supply are a function of the degree to which such policies and regulations limit or reduce the principal power plant sources of GHG emissions — carbon dioxide (CO_2) and nitrous oxide (N_2O) — and thereby limiting electricity production from fossil fuels.

The resulting influence of federal, state, and provincial regulation of GHG emissions on the combustion of fossil-fuels for power generation could restrict electricity production in the 2006–2015 assessment period. The potential reliability impacts of GHG limits on fossil-fueled power generation will depend on the transition period for coming into compliance with any new regulations.

Energy Policy Act of 2005

Two specific areas of EPACT under development in 2006 are intended to improve reliability through enhanced transmission infrastructure siting and enforcement:

1. Congestion Study and Designation of National Interest Electric Transmission Corridors (NIETCs) (Section 1221)

Section 1221 requires the Secretary of Energy to publish an electric transmission congestion study for comment by August 8, 2006. Further, the Act provides that after receiving and considering public comments, the Secretary may designate selected areas as NIETCs. Designation as a NIETC gives the Federal Energy Regulatory Commission (FERC) backstop authority under certain conditions to preempt state siting processes and approve the siting of transmission facilities within the corridors.

The congestion study, which has been completed, identifies geographic areas where electric transmission congestion is already severe, or becoming so, and where additions to transmission capacity (or suitable alternatives) could lessen the adverse impacts on consumers. The study builds upon existing transmission planning studies and other analyses prepared by regional reliability councils, regional transmission organizations (RTOs), utilities, and others. The study was also informed by congestion modeling of the Eastern and Western Interconnections.

2. Designation of energy corridors on federal lands (Section 368)

Section 368 directs the Secretaries of Agriculture, Commerce, Defense, Energy, and the Interior (the Agencies) to designate under their respective authorities corridors on Federal land in the 11 Western States (Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming) for oil, gas and hydrogen pipelines and electricity transmission and distribution facilities (energy corridors). The Agencies have determined that designating corridors as required by Section 368 of the Act constitutes a major federal action which may have a significant impact upon the environment within the meaning of the National Environmental Policy Act of 1969 (NEPA). For this reason, the Agencies intend to prepare a programmatic environmental impact statement (PEIS) entitled, “Designation of Energy Corridors on Federal Land in the 11 Western States” (DOE/EIS-0386) to address the environmental impacts from the proposed action and the range of reasonable alternatives. DOE and BLM will be co-lead agencies for this effort, with the U.S. Department of Agriculture’s Forest Service (USFS) participating as a cooperating agency. Similar work will subsequently be conducted for Federal Lands in the eastern states.

ADEQUACY ASSESSMENT

Demand and Resource Projections

NERC expects electricity demand to grow by about 68,675 MW through the summer of 2011. Projected resource additions over this same period total about 39,937 MW, depending upon the number of merchant plants assumed to be in service. However, due to the short lead-time for developing some types of generation, this difference could be offset by assignment or development of capacity that has not yet been committed or announced.

The average annual growth in United States summer peak demand for 2006–2015 is 1.9 percent. This is slightly lower than the 2.0 percent average annual growth in actual peak demand since 1995. In Canada, average annual growth in winter peak demand over the next ten years is 1.1 percent, which is slightly higher than the 0.9 percent average annual growth in actual demand since 1995. Year-to-year demand growth rates can vary due to variations in economic conditions and weather. Also, actual demands are not corrected for weather or other conditions.

Peak demand projections shown on Figures 2 and 3 represent an aggregate of weather-normalized regional member projections. NERC has not prepared its own independent demand forecast. Individual local entities make appropriate assumptions dealing with diversity, weather, and economic conditions, which are key drivers of the demand forecast. Individual local area forecasts typically are developed using a "multi-model" approach that comprises econometric modeling using national, regional, and state/provincial economic projections, as well as end-use modeling of local service area conditions.

NERC's Load Forecasting Working Group (LFWG) develops bandwidths around the aggregate United States and Canadian demand projections to account for uncertainties inherent in demand forecasting. The average annual growth in the "high" and "low" band U.S. summer peak demands are 2.4 percent and 1.4 percent, respectively. In Canada, the "high" and "low" band growth rates in winter peak demands are 1.7 percent and 0.3 percent, respectively.

Forecast Bandwidths

Forecasts are based on probabilities and cannot precisely predict the future. Instead, forecasts typically encompass a range of possible outcomes to address future uncertainty. Each demand projection, for example, represents the most likely future outcome. Capacity resources historically have been planned to meet the most likely demand with an additional reserve to meet unusual conditions.

For planning purposes, not only is an estimate of the most likely future outcome useful, but so are those of potential variations. Accordingly, LFWG develops upper and lower confidence bands around demand projections. The confidence bands represent an 80 percent probability that future demand will occur between the upper and lower bands. Consequently, the chance that demand will be below the lower band is 10 percent and the chance that demand will be above the upper band is 10 percent. Demand projections and their associated bandwidths are updated each year to reflect the latest conditions.

The Regional Self-Assessment section of this report includes regional bandwidths to more clearly show the variability of demand within the respective regions.

Figures 2 and 3 also show overlays of projected capacity resources on the projected demand bandwidths. The NERC regions report all capacity committed to serve demand within their borders, but capacity that is not committed to serve a specific demand might not be reported to NERC through its traditional data collection process.

Accurately predicting the exact number and in-service dates of future capacity additions that merchant developers will actually construct is difficult. To supplement these traditional data sources in order to better understand the potential impacts of new generators, the RAS has enlisted the services of Energy Ventures Analysis, Inc. (EVA) to provide detailed project information[8]. Using this information, announced plans for new merchant plants were screened to establish those most likely to be built.

Figure 2 shows three resource curves: the first is based on NERC regional projections; the second adds uncommitted capacity to regional projections; and the third is the subcommittee's best estimate of future capacity resources (existing plus EVA).

[8] EVA maintains a database of all proposed new power plants in the United States and tracks various milestones associated with the completion of the projects, including applications for environmental permits, siting, acquisition of equipment, financing, and contractual arrangements to sell the output of the facilities. Using this information, announced new merchant plants were screened to establish those most likely to be built. For Canada, the RAS utilized a combination of EVA and regional data to compile comparable statistics.

Figure 2: United States Summer Capacity Versus Demand Growth

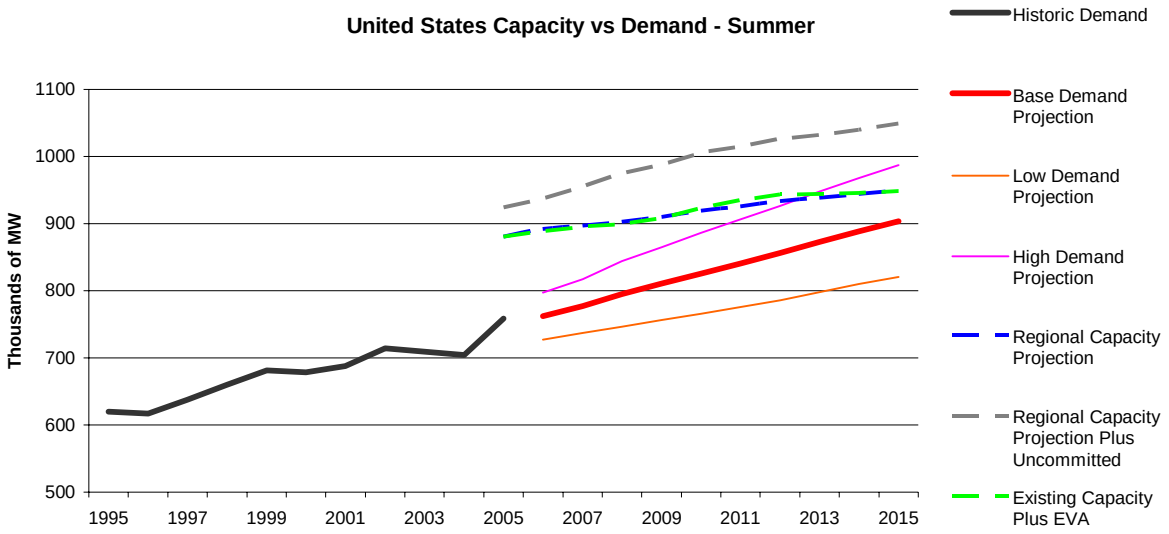
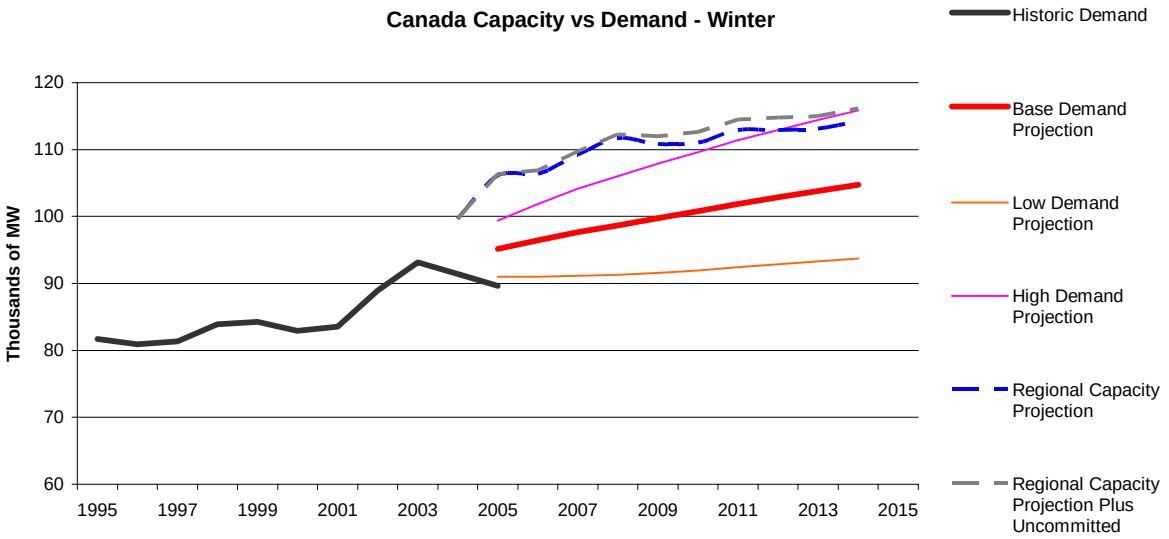


Figure 3: Canada Winter Capacity Versus Demand Growth



Capacity Additions

The overall projected amount of new generation is decreasing. In some areas, generation has been overbuilt and a decrease in new construction is an expected response to the over-supply situation. In other areas, increases in generation additions that have not yet been identified may be continuing but because of the short lead time for construction of some generating facilities, those projects may not be included in announced plans.

Table 1: Aggregate Capacity Under Development by Type

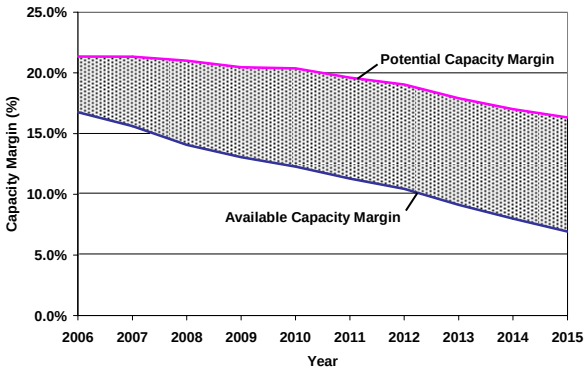
Capacity Type	Capacity Additions, MW			
	1998 to 2005	2006 to 2012	2013 to 2015	2006 to 2015
United States				
Combined Cycle	143,694	34,074	-	34,074
Simple Cycle	75,314	3,890	-	3,890
Coal	2,168	29,404	3,885	33,289
Nuclear	2,567	2,366	2,550	4,916
Wind	5,705	8,769	-	8,769
Other	1,572	3,170	-	3,170
Total U.S.	**231,019**	**81,672**	**6,435**	**88,107**
Canada				
Combined Cycle	80	-	-	-
Simple Cycle	4,740	4,653	-	4,653
Coal	490	450	-	450
Nuclear	-	-	-	-
Wind	-	1,440	-	1,440
Other	-	203	200	403
Total Canada	**5,310**	**6,746**	**200**	**6,946**

Source — EVA

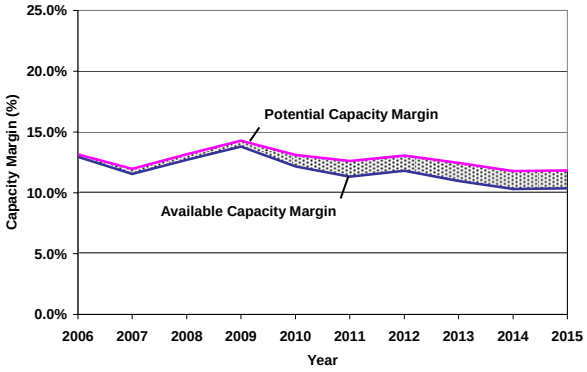
Capacity Margins

Available capacity margins in the United States and Canada are projected to decline over the 2006–2015 period. Margins vary from region to region, as does the amount of *uncommitted resources* reported.

Capacity margins in United States decline throughout ten-year period. Uncommitted resources offer significant potential.



Capacity margins in Canada steady in short term; decline in long term.



Capacity Margin — 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.

Available Capacity Margin — The difference between ***committed*** capacity resources and peak demand, expressed as a percentage of capacity resources.

Potential Capacity Margin — The difference between ***committed*** plus ***uncommitted*** capacity resources and peak demand, expressed as a percentage of capacity resources.

Committed Capacity Resources — Generating capacity resources that are existing, under construction, or planned that are considered available, deliverable, and committed to serve demand, plus the net of capacity purchases and sales.

Uncommitted Capacity Resources — Capacity resources that 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 margins drop below minimum target levels in ERCOT, MRO, New England, RFC, and Rocky Mountain and Canada areas of WECC in the next 2–3 years, with many other areas reaching minimum levels later in the ten-year period. However, all regions have some additional resources potentially available in the form of *uncommitted resources* that exist, are under construction, or are in the planning stage, which offer the potential to meet minimum target levels. Actions needed to make these resources available when needed include: returning "mothballed" units to active service; entering into power purchase agreements for existing or new resources; upgrading transmission to provide access to resources that would not otherwise be deliverable; and developing and bringing into service projects that are in generator interconnection queues.

Energy Growth Projections

Figures 4 and 5 show ten-year projections of net energy for load for the United States and Canada along with the high and low bandwidth projections. The average annual growth in United States. net energy for load is 1.8 percent, which is the same annual growth rate experienced since 1995. The "high" and "low" band growth rates for the United States are 2.2 percent and 1.4 percent, respectively. In Canada, the projected average annual growth in net energy for load is 1.2 percent, compared percent to a 1.8 percent growth rate since 1995. The "high" and "low" bands are 1.7 percent and 0.7 percent, respectively.

Figure 4: United States Net Energy for Load 2006–2015

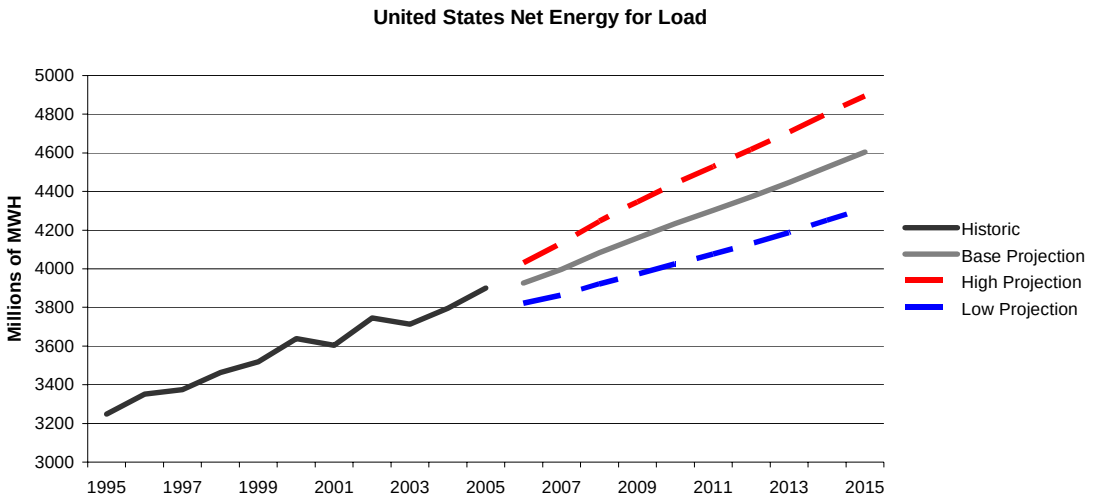
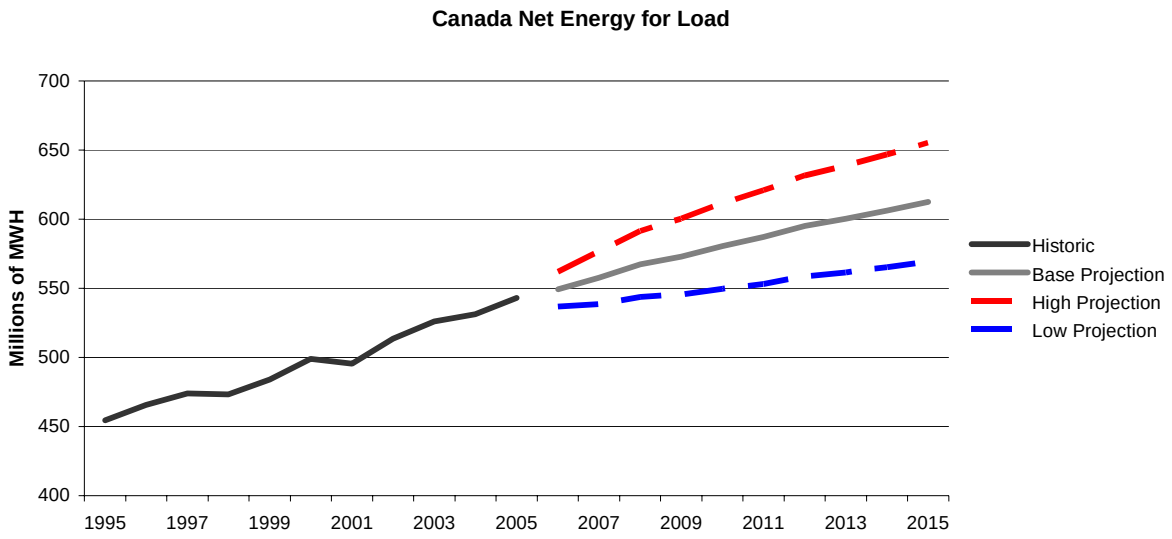


Figure 5: Canada Net Energy for Load 2006–2015



Regional Self-Assessments

Introduction

Regional Resource and Demand Projections

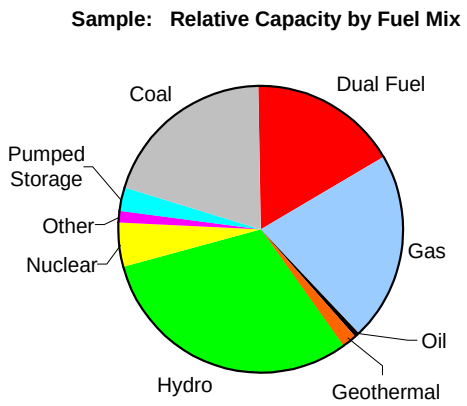
The figures in the regional self-assessment pages show the regional historical demand, projected demand growth, capacity margin projections, and generation expansion projections reported by the regions. These data are augmented by generation expansion data from EVA.

Capacity Fuel Mix

The regional capacity fuel mix charts, shown as a comparative percent of regional generating capacity between 2005 and 2011, illustrate each region's relative dependence on various fuels for its reported generating capacity. The charts for each region in the regional self-assessments are based on the most recent data available in NERC's Electricity Supply and Demand database.

Note: The category "Other" may include capacity for which a fuel type has yet to be determined.

Sample — Relative Capacity by Fuel Mix



ERCOT

Demand

ERCOT has increased its projected average annual demand growth rate over the assessment period from 1.8 percent used last year to 2.3 percent for this year's assessment. That increase is due to the effect of the historical trend and updated econometric forecasts.

ERCOT's peak demand forecasts are based on normal weather defined by a temperature normalized profile from the last 11 years of historical hourly temperatures. Unusually hot or cool weather can result in actual demands above or below the forecast. The ERCOT reserve margin of 12.5 percent was established to accommodate this demand variation along with unit forced outages.

The analysis of variability in load and weather volatility was performed with a system forecasting model that runs a Monte Carlo simulation of a median weather profile and a 90th percentile profile forecast using weather and calendar variables. The 90th percentile forecast is about 5.5 percent higher than the median.

Energy

The energy forecast for the assessment period indicates an average 2.1 percent growth rate. This growth rate is little changed from last year's assessment forecast. The actual growth rate from 2004 to 2005 was 3.5 percent due to milder weather in 2004 than in 2005.

Resources

ERCOT has set a minimum planning reserve margin target of 12.5 percent that equates to a capacity margin of 11 percent. This was based on a reliability study, which concluded that the margin should provide about a one-day-in-ten-years loss-of-load expectation.

Resources that are counted in determining ERCOT's margins are:

- Existing in-service capacity based on demonstrated summer net dependable capacity (except for wind generation and switchable capacity that has the capability to switch between ERCOT and other interconnections).
- Future planned generation with signed interconnection agreements.
- Fifty percent of dc tie capacity.
- Switchable capacity to the extent its owners have indicated they intend to be in the ERCOT market.
- Based on historical performance on peak, 2.6 percent of existing in-service wind capacity and future wind capacity with signed interconnection agreements.
- Mothballed capacity based on when its owners estimate it will be returned to service.

Generation owners are required to provide ERCOT at least 90 days notice of extended planned shut-downs of generation so ERCOT can enter into reliability must run (RMR) contracts for those units to keep them available if needed for system reliability. ERCOT currently has contracts with 267 MW of RMR capacity in the Laredo and Bryan areas that is needed to provide local voltage support and keep facility loadings below transmission limits. ERCOT has exit strategies to improve the transmission system so this RMR capacity can be phased out over the assessment period.

ERCOT has approximately 672 MW of new fossil-fueled generating capacity with existing signed interconnection agreements expected to come on-line between 2006 and 2011. An additional 6,100 MW of fossil-fueled, mostly coal, capacity has been publicly announced but is not included in forecasted resource capability. Almost 950 MW of new wind generation is also expected between 2006 and 2011. ERCOT does not maintain a new generation forecast beyond 2011.

A total of 820 MW of dc tie transfer capability exists between ERCOT and SPP and 36 MW of capability between ERCOT and Mexico's Comision Federal de Electricidad. Entities in ERCOT anticipate importing via the SPP dc ties 120 to 138 MW of firm purchases over the assessment period. Entities in SPP can call on 162 MW of capacity in ERCOT and it is classified as a capacity sale from ERCOT. These purchases and sales have little impact on ERCOT's ability to meet demand requirements.

Fuel

Curtailment of natural gas supply is possible during winter months, which is an issue due to the fact that over 60 percent of the generating capacity in ERCOT is fueled by natural gas. Typically, natural gas supply is not a problem for gas-fired generation in the summer months due to the absence of heating demand competition for supply. Gas generation currently has no market incentive or nonmarket mechanism to maintain dual fuel capability and storage, typically with fuel oil, which would be critical to maintaining generation adequacy during extended periods of gas curtailments. ERCOT has a procedure in place to request current status of fuel supply contracts, backup fuel supplies, and unit capabilities if

severe cold weather is expected in the seven-day forecast. This information would be used to prepare operation plans.

ERCOT will initiate its Emergency Electric Curtailment Plan (EECP) (see ERCOT Protocols Section 5.6.6.1 at http://www.ercot.com/mktrules/protocols/current.html) if available capacity gets below required levels due to gas curtailments or any other reason. The EECP maintains the reliability of the interconnection by avoiding uncontrolled load shedding. During emergency conditions, ERCOT coordinates gas supply priorities with the Texas Railroad Commission.

Transmission

The existing bulk power system within ERCOT is comprised of 38,000 miles of transmission lines. ERCOT, along with its transmission owners' member systems, continues to plan for a reliable bulk power system and plans to add 1,601 miles of 138-kV, and 835 miles of 345-kV transmission lines in the 2006–2010 time period. ERCOT members invested over $345 million in new transmission lines and system upgrades in 2005, and are planning transmission capital expenditures of more than $2.2 billion over the next five years.

The major transmission constraints in ERCOT expected during the assessment period are:

- Transfers into the Dallas-Fort Worth area from northeast and central Texas
- Transfers into Houston from north and south Texas
- Transfers out of the west Texas wind generation area
- Transfers into and across the Rio Grande Valley
- Local operating reliability needs in Laredo

These constraints will require redispatch of generation by ERCOT and, in the case of Laredo, RMR contracts with generators that would have otherwise shut down as previously discussed. Their main impact is on economics as they have operational solutions to maintain reliability. Approximately 650 circuit miles of major new 345-kV lines in central, south, and north Texas are scheduled to be placed in service between 2006 and 2010 to relieve these constraints. Several lines in the Dallas-Fort Worth area are scheduled to go in service by the end of 2006 that will increase transfer capability into that area. In 2007, the new Hillje station with lines to South Texas Project and W.A. Parish will increase import capability into Houston. A line from San Miguel to Laredo scheduled for service in 2010 will allow termination of the RMR contract in Laredo.

Transmission planning is increasingly using voltage and transient stability analysis. Voltage stability has become a more pressing concern with increasing power transfers in ERCOT and lessons learned from the 2003 Northeast blackout.

Operations

No major facility outages or environmental requirements are expected during the assessment period that would significantly impact reliable operations. Ongoing operational challenges during the assessment period are expected to center around transmission congestion management and operating with reduced capacity margins.

In the short term, a number of temporary post-contingency remedial action plans (RAPs) and special protection systems (SPSs) that maximize transfer capabilities over the existing system and reduce redispatch (but require special operator attention) will be implemented as needed. Improvements to the transmission system are planned to eliminate many of the existing RAPs and SPSs over the next few years.

Capacity margins will likely be at minimum levels over the assessment period compared to the relatively high levels experienced over the last few years. This, coupled with resource vulnerability to winter gas curtailments previously discussed, will increase the likelihood that operators will need to initiate emergency procedures such as the EECP in the future. ERCOT plans to have an Operator Training Simulator available in 2007 to train operators on simulated EECP and other unusual events.

ERCOT operators are able to do real-time voltage stability analysis. This analysis addresses one of the recommendations from the report on the 2003 blackout.

The Public Utility Commission of Texas (PUCT) has approved a major market redesign that would change current congestion management procedures from a zonal to a nodal-based system. This transition, currently scheduled for January 1, 2009, would present challenges in implementing new operating systems, but should also improve the efficiency of transmission congestion management.

Assessment Process

ERCOT prepares five- and ten-year projections of capacity, demand, and reserves at least annually to evaluate whether the system will meet the reserve margin target of 12.5 percent (11 percent capacity margin). ERCOT also performs power flow analyses required to assess compliance with ERCOT Planning Criteria, which comply with NERC Planning Standards. An annual study and report is made to the PUCT highlighting congested areas of the transmission system and recommended projects to mitigate that congestion. ERCOT facilitates an open planning process through three regional planning groups made up of transmission owners and operators and other ERCOT market participants. Any party can comment on ERCOT planning studies and propose new projects or additional studies for review by the appropriate regional planning group.

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).

ERCOT Capacity and Demand

Figure 7: ERCOT Net Energy for Load

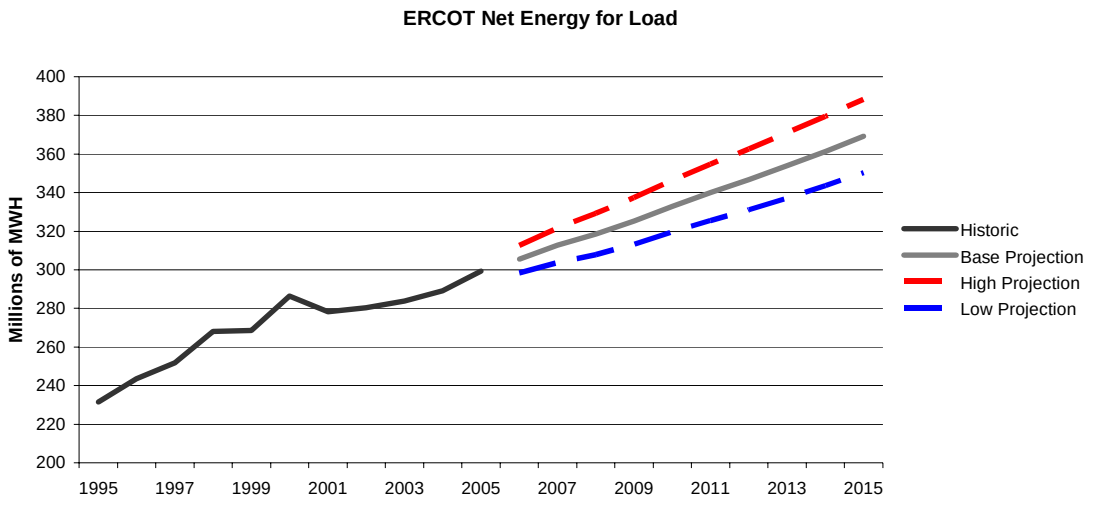


Figure 8: ERCOT Capacity Margins — Summer

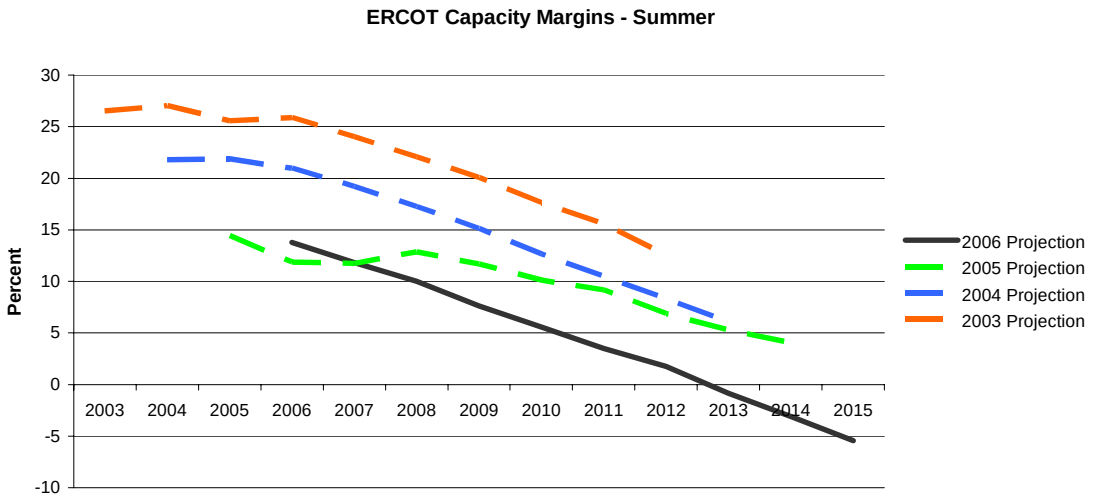


Figure 9: ERCOT Capacity Versus Demand — Summer

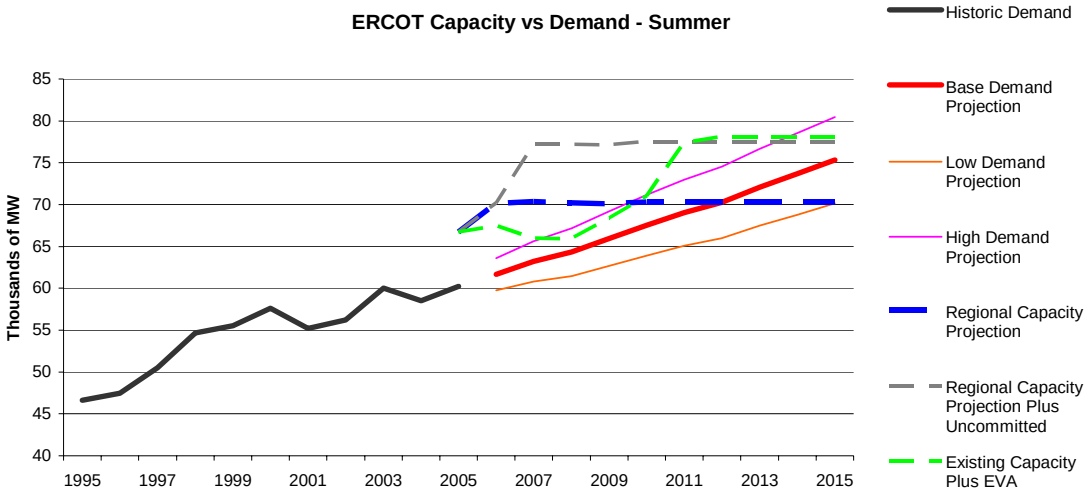
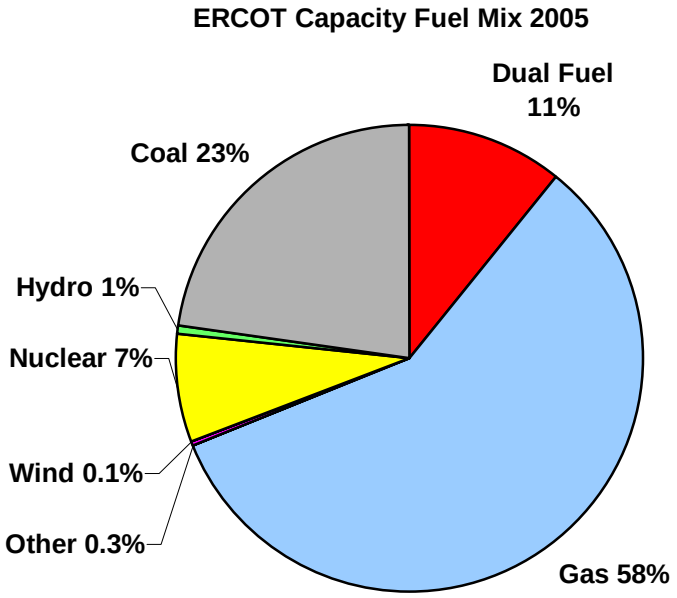
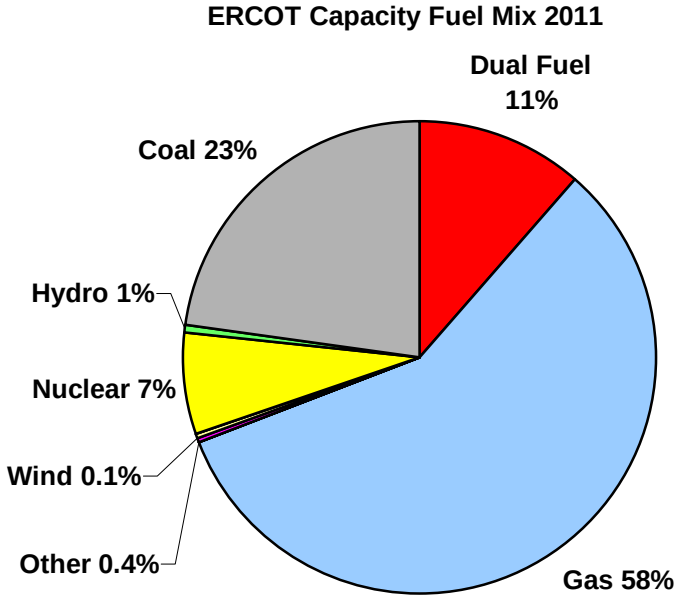


Figure 10: ERCOT Capacity Fuel Mix for 2005 and 2011





FRCC

Demand

FRCC members use historical weather databases consisting of as much as 57 years of data for the weather assumptions used in their forecasting models. Historically, FRCC has high-demand days in both the summer and winter seasons. However, because the region is geographically a subtropical area, a greater number of high-demand days normally occur in the summer. As such, this report will address the summer load values.

The 2006 ten-year demand forecasts for FRCC exhibited similar growth trends to 2005 projections. The annual net internal demands for the summer months are projected to rise at a compounded average annual growth rate of 2.4 percent from 42,761 MW in 2006 to 53 108 MW in 2015.

Individual companies within FRCC use a bandwidth analysis and/or a Monte Carlo simulation to assess the peak demand uncertainty and variability. For the bandwidth analysis, the company develops a bandwidth around the projected or most likely demand (50 percent probability). The purpose of developing bandwidths on peak demand is to quantify all uncertainties of demand. This would include weather and nonweather demand variability such as demographics, economics, and price of fuel and electricity.
Monte Carlo simulations on peak demands are performed to arrive at a probabilistic distribution as to range and likelihood of this range of outcomes of peak demand. Factors that determine the level of demand for electricity are assessed in terms of their own variability and this variability incorporated in the simulations. 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 at a given level of probability.

An FRCC methodology for developing bandwidths for the region forecast has not been developed; however, FRCC is assessing possible methodologies to develop region forecast bandwidths.

Energy

The 2006 ten-year energy forecast for FRCC displayed growth similar to the 2005 forecast. Yearly energy consumption is expected to rise from 226,544 GWh by 2.8 percent over the next decade, to 297,561 GWh, exactly matching last year's projected ten-year growth of 2.8 percent.

Resources

The Florida Public Service Commission (PSC) requires all Florida utilities to file an annual ten-year site plan that details how each utility will manage growth for the next decade. The data from the individual plans is aggregated into the FRCC Load and Resource Plan that is produced each year and filed with the Florida PSC. The FRCC 2006 Load and Resource Plan shows FRCC reserve margins over the winter and summer peaks for the next ten years to equal or exceed 20 percent. All years are well above the 15 percent reserve margin standard established by FRCC. The calculation of reserve margin does not include any uncommitted capacity (see Tables 3a–3d).

FRCC members are projecting a net increase (i.e., additions less removals) of 16,617 MW of new installed capacity over the next decade, compared to the 17,740 MW projected in last year's ten-year forecast. Of this increase, 10,799 MW are designated for gas-fired operation in either simple-cycle or combined-cycle configurations, and 5,524 MW are anticipated for coal-fired operation. Gas-fired generation continues to dominate a high percentage of new generation. In 2005, natural gas generation accounted for 21,974 MW of generation, which is 46 percent of FRCC's installed capacity. By 2015, it is expected that natural gas generation will account for 32,953 MW of generation, which will be 52 percent of FRCC's installed capacity.

Approximately 4,913 MW of merchant plant capability are located in FRCC, of which 3,763 MW are under firm contract. The planned construction of merchant plants has decreased significantly over prior years' projections, and the amount of merchant generation that may come on-line in the next ten years is dependent on a number of factors that are not capable of being forecasted at this time. These include the results of contractual negotiations for the sale of announced capacity, transmission interconnections and/or service requests and associated queuing issues, and federal, state and local siting requirements.

Currently, 1,552 MW are being imported into the region on a firm basis and about 839 MW are dynamically dispatched out of the Southern subregion, which together account for about 5 percent of the reserve margin. These firm imports and dynamically dispatched capacity have firm transmission service to ensure deliverability into FRCC. No firm long-term sales to other regions are anticipated.

FRCC conducted a loss of load probability (LOLP) analysis of peninsular Florida for the 2005–2014 study horizon that examined both the resource plans and load forecasts of state utilities. Factors included extreme summer and extreme winter demand scenarios; availability of SERC firm and nonfirm imports; and availability of demand-side management. The study concluded that the existing and planned resource additions over the coming decade will result in a predicted LOLP that is less than the one-day-in-ten-years criterion.

Fuel

The FRCC Regional Load and Resource Plan is developed on an annual basis and includes specification of primary and secondary fuel sources for both generating facilities and prospective units planned over the ten-year horizon. 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 coordination has provided the data necessary to perform short-term natural gas availability assessments in order to provide operators with near-term health of the gas delivery system, along with the basis for other operational recommendations up to and including regional appeals for conservation. FRCC continues to assess and coordinate responses to regional fuel supply impacts and issues, including fuel inventory and alternate supply availability, as they are identified.

During peak demand periods, operators within FRCC will use the fuel supply infrastructure to its maximum capability as most fuel delivery infrastructure is designed around projected loading. The type of infrastructure and preferred generation dispatch used would be based on economic conditions and surrounding the types of fuels, along with availability of external purchased power. Typically, during peak summer conditions, some alternate fuel unit dispatch may be used depending on system economics.

Fuel supplies continue to be adequate for the region. FRCC continues its work on a more detailed natural gas pipeline and electric interdependency study process. FRCC has begun development of a high-level, transient gas flow model to study and finitely analyze the gas pipeline system and its impact on reliability in peninsular Florida. Additional data related to natural gas use within the region has been collected, and input into the gas flow model and scenarios are being developed to perform reliability analyses.

Transmission

The results of the short-term (first five years) study for normal, single, and multiple contingency analysis of the FRCC region show that there is potential thermal and voltage violations occurring in Florida. However, these potential violations can be resolved with pre-determined operational procedures. Generation redispatch, sectionalizing, implementation of load management, planned load shedding, reactive device control, and transformer tap adjustments successfully mitigate all the reportable load and voltage violations appearing in the first five years. However, potential violations on the transmission lines between southwestern central Florida generation and the greater Orlando load area would require more extensive operational procedures. Permanent solutions are under review to resolve these

deficiencies with new transmission projects. Based on the committed projects and expected generation dispatch, it is expected that these operational procedures will continue in this area until 2010. Higher than expected loads or extended generation outages could worsen the situation as well. However, additional operation strategies have been developed to address these future conditions and these strategies will continue to be evaluated to ensure system reliability.

The long-range (remaining five years) study results reveal developing problems in several areas in the FRCC region that the responsible utilities acknowledge will be studied in the near future to define needed improvements to the transmission system. These areas include northwest Florida around Tallahassee, the Avon Park area, north Florida around the site of a proposed coal-fired generation project in Taylor County, and new generation locations in central Florida. These new generation projects will have a major impact on the bulk power system in the region. Currently, these areas are being studied to determine the projects required to meet the long-range needs of the transmission system.

Interregional transmission studies are performed each year to evaluate the transfer capability between the Southern subregion of SERC and the FRCC for the upcoming summer and winter seasons. Joint studies of the Florida/Southern transmission interface have verified the current import capability of 3,600 MW into the FRCC region, and the export capability of 1,300 MW.

No scheduled transmission maintenance outages of any significance are planned over the forecast horizon, particularly during seasonal peak periods. Scheduled transmission outages are typically performed during off-seasonal peak periods to minimize any impact to the bulk power system.

Currently, individual members plan to construct 477 miles of 230-kV transmission lines during the 2006–2015 assessment to continue to meet expected load growth, integrate new generation sources into the bulk transmission system and resolve the potential reliability issues.

Operations

FRCC has a security coordinator agent (reliability coordinator) that monitors real-time system conditions and evaluates near-term operating conditions. The security coordinator uses a region-wide state estimator and contingency analysis program to evaluate current system conditions. These programs are updated with data from operating members every ten seconds. These tools enable the FRCC security 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.

The FRCC region experienced significantly higher load levels than were forecast during the summer of 2005. This coupled with additional generation in the southwest portion of central Florida, created increased west-to-east flow levels across the central Florida metropolitan load areas.

Several transmission modifications have been accelerated and were implemented this spring to increase the operational margins and transmission configuration options for the area. If the region experiences comparable load levels to the summer of 2005, the same sensitivities to area dispatches and transmission configuration are expected as operational issues until additional transmission is constructed. Should these operational issues arise, operational procedures (operational work-arounds with pre-planning and training) will manage the impacts to the bulk power system in the area to ensure reliable operations.

Even with increased reliance on operational procedures to resolve potential transmission loading concerns through 2011, FRCC does not foresee any reliability issues for the first five years of the study period. In addition, with the proposed transmission expansion projects, FRCC does not foresee any reliability issues in the longer term.

Assessment Process

FRCC members plan for facility additions on an individual basis. However, they also provide data to FRCC to update and maintain the regional databases. These regional databases are used in the reliability assessment process to ensure the continued reliability of the bulk power system. FRCC follows a formal reliability assessment process by which it uses a committee and working group structure to annually review and assess reliability issues that either exist or have the potential to develop. This process determines which areas deserve closer scrutiny in the planning and operating studies that will be performed during the year. FRCC members use the results of these studies to ensure that the FRCC region is able to meet the reliability needs of the future.

Study results are also provided to the Florida PSC, which has the authority to require installation or repair of generating plants and transmission facilities, if it has reason to believe that inadequacies exist with respect to grid reliability.

In April 2005, FRCC adopted a very comprehensive and in-depth transmission planning process for the region. This process begins with the annual consolidation of the individual long-term transmission plans of all of the transmission owners in FRCC. A detailed analysis of the resulting regional plan will be conducted annually by the FRCC Planning Committee. The assessment will be a robust analysis and will include an examination of multiple expected system conditions and other sensitivities.

The Planning Committee will report its findings, including recommendations for changes or additions to individual transmission owner's plans, to the FRCC Board of Directors for approval. The process also provides for resolution of any identified unresolved issues. The resolution may include the use of an independent evaluator to study and provide input to FRCC. A final report will be sent to the Florida PSC.

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).

FRCC Capacity and Demand

Figure 11: FRCC Net Energy for Load

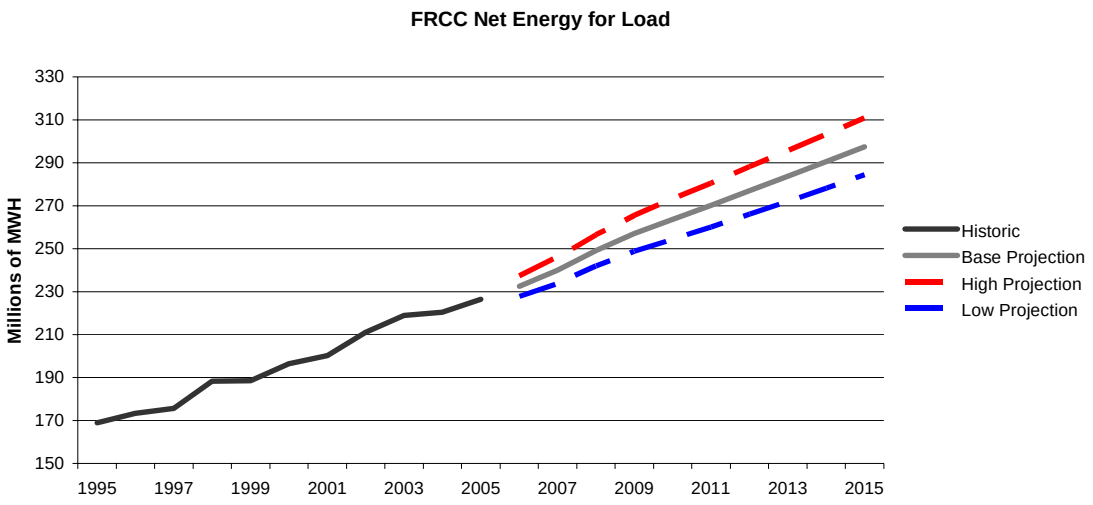


Figure 12: FRCC Capacity Margins — Summer

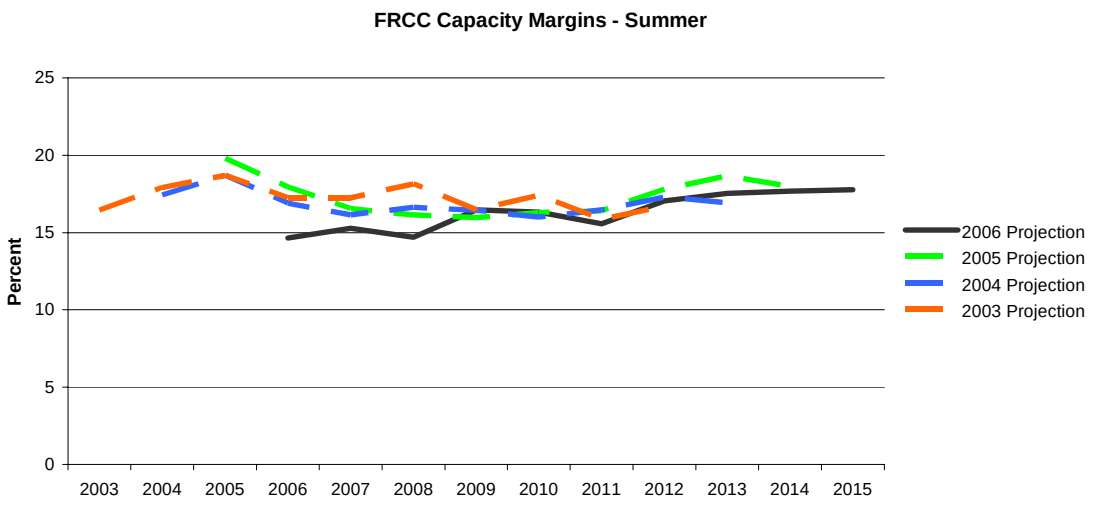


Figure 13: FRCC Capacity Versus Demand — Summer

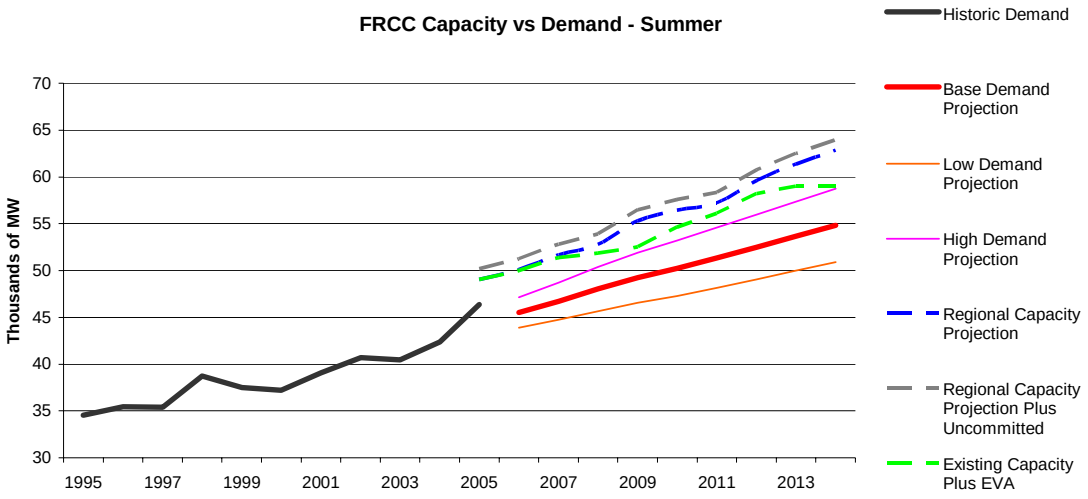
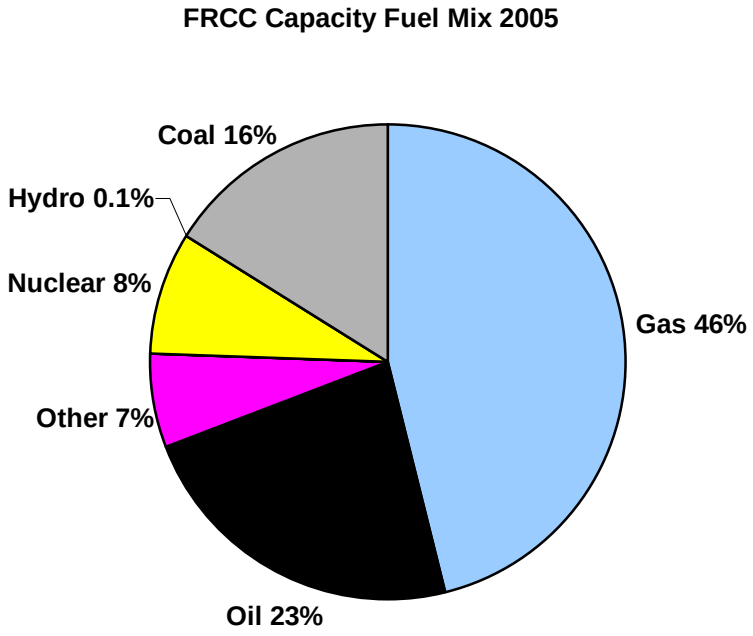
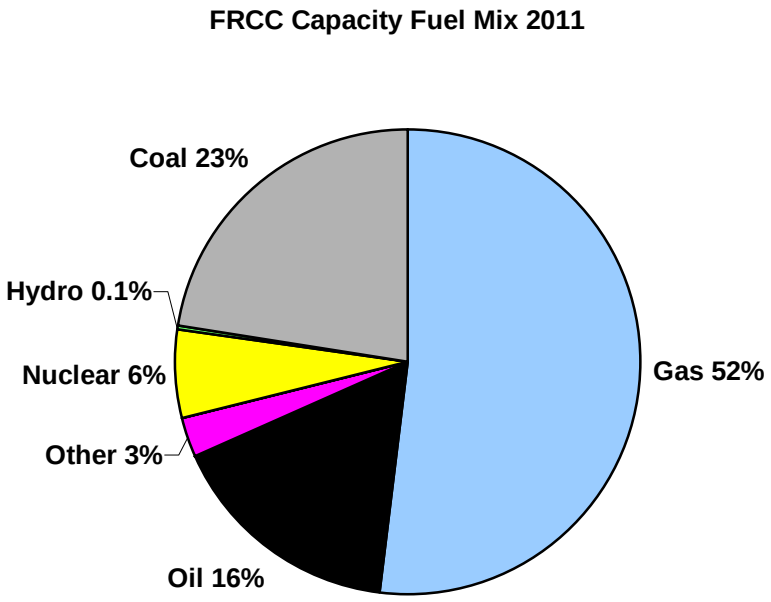


Figure 14: FRCC Capacity Fuel Mix for 2005 and 2011





MRO

The MRO replaced the Mid-Continent Area Power Pool (MAPP) as a NERC regional reliability council in January 2005. MAPP continues to exist as a regional transmission group and maintains the MAPP Generation Reserve Sharing Pool (GRSP) and the MAPP Regional Transmission Committee. As of January 2006, MRO acquired additional members from the former Mid-America Interconnected Network, Inc. (MAIN) regional reliability council. This assessment includes those new members.

Demand

The MRO-U.S. summer peak demand is expected to increase at an average rate of 1.9 percent per year during 2006–2015, as compared to 2.0 percent predicted last year for 2005–2014. The MRO-U.S. 2015 noncoincident summer peak demand is projected to be 55,518 MW. The MRO-U.S. 2015 noncoincident summer peak demand representing the MAPP membership was 37,068 MW, which represents a 4.1 percent increase compared to the 2014 projected demand level of 35,612 MW. The MRO did not make a comparison to last year's numbers for the entire footprint as data for the new members was not available for the 2005–2014 assessment.

MRO members continue to forecast load based on normal weather conditions.

The MRO-Canada summer peak demand is expected to increase at an average rate of 0.84 percent per year during 2006–2015, as compared to 1.17 percent predicted last year for 2005–2014. The MRO-Canada 2015 noncoincident summer peak demand is projected to be 6,282 MW. This projection is 1.35 percent below the 2014 noncoincident summer peak demand predicted last year (6,367 MW).

The MRO-Canada winter peak demand is expected to increase at an average rate of 0.8 percent per year during 2006–2015, as compared to 0.8 percent predicted last year for 2005–2014. The MRO-Canada 2015 noncoincident winter peak demand is projected to be 7,641 MW. This projection is 1.6 percent above the 2014 noncoincident winter peak demand predicted last year (7,521 MW).

Long-term sales to other regions where the purchasing entities are known are expected to decrease from their current level of 446 MW in 2005 to about 144 MW in 2015. Long-term purchases from other regions where the selling entities are known are expected to decrease from their current level of 2,784 MW in 2005 to about 1,600 MW in 2015. Based on information from MRO members, no purchases or sales where the buyer or seller is unknown were reported for 2006–2015.

Both the MAPP GRSP and the former MAIN MRO members utilize a load forecast uncertainty factor (LFU) within the determination of adequate generation reserve margin levels. The LFU considers both uncertainty attributable to weather conditions and economic conditions and is factored into the LOLE study used to determine adequate reserve margin levels. MRO does not conduct a review of weather impacts on an aggregate basis for the entire region.

Energy

The 2006 annual forecast energy consumption for MRO total (262,722 GWh) is 1.2 percent above the 2005 summer actual energy (259,525 GWh).

The MRO 2015 annual forecast energy is projected to be 305,891 GWh for the entire footprint. The MRO annual forecast energy is expected to increase at an average rate of 1.8 percent per year during 2006–2015. The MRO did not make a comparison to last year's numbers for the entire footprint as data for the new members was not available for the 2005–2014 assessment.

The 2006 annual forecast energy consumption for MRO-U.S. (220,006 GWh) is 1.6 percent above the 2005 annual actual energy (216,633 GWh).

The MRO-U.S. annual forecast energy is expected to increase at an average rate of 2.0 percent per year during 2006–2015. The MRO-U.S. 2015 annual forecast energy is projected to be 259,074 GWh. The 2006 annual energy consumption for MRO-Canada (42,716 GWh) is 0.4 percent below the 2005 annual actual energy (42,892 GWh).

The MRO-Canada annual forecast energy is expected to increase at an average rate of 1.1 percent per year during 2006–2015, as compared to 1.3 percent predicted last year for the 2005–2014 period. The MRO-Canada 2015 annual forecast energy is projected to be 46,817 GWh.

Resources

Adequate generating resources for MRO-Canada are forecasted over the ten-year period. Reserve levels range from 29.5 percent in the summer of 2006 to 42.5 percent during the summer of 2015. Reserve levels vary slightly during the winter seasons from 25.4 percent in winter of 2005–2006 to 26.8 percent during the winter 2014–2015.

Current planned capacity reported in the MRO-U.S. region is below MRO requirements for reserve capacity obligation during 2010–2015. For the purpose of this assessment, the MRO is utilizing the MAPP restated agreement reserve capacity obligation of 15 percent, which is the same as a 13.04 percent minimum capacity margin requirement. The summer reserve margin for MRO-U.S. is forecast to decline from a high of 21.0 percent in 2006 to 14.2 percent in 2010 and 2.4 percent in 2015. These figures include an additional 3,423 MW of new generation for the period of 2006–2015 as reported to NERC in the EIA-411 report.

The MAPP 2005 Update to the 2004 Regional Plan, however, has reported 12,439 MW of new generation for the period of 2004–2013. The capacity difference (9,016 MW) between the MAPP 2005 Update to the 2004 Regional Plan and the EIA-411 data is the uncommitted capacity that has not been sited or was not reported through the data collection process used to prepare the NERC assessment report. Therefore, for the next ten-year period, the MRO capacity margins are likely higher than those shown above. With that amount of uncommitted capacity reported in the period of 2004–2013, the MRO does not expect any capacity deficits to occur during the assessment period.

Further assurance of generation adequacy is expected through the development of an MRO Planned Resource Adequacy Requirement Standard. This standard is currently in the commenting period.

Fuel

As a region, the MRO does not specifically address fuel supply interruptions on a prospective basis in the long-term assessment. Fuel supply interruptions tend to be local in nature, that is, the failure of the supply network is due to an equipment breakdown or other problem in a specific location. These types of failures in the supply network are difficult to predict, generally short lived, and contained in a specific area. MRO members have taken actions in the past to resolve local fuel supply issues. Such actions have included alternate transportation arrangements, fuel switching, and fuel conservation. MRO members are expected to take appropriate action to resolve any short-term fuel supply interruptions into the future and secure adequate fuel supplies throughout the assessment period.

Transmission

The existing transmission system within MRO-U.S. is comprised of 7,328 miles of 230-kV, 8609 miles of 345-kV, and 343 miles of 500-kV transmission lines. The 2005 Update to the 2004 Regional Plan

showed that the MRO-U.S. members planned to add 1,104 miles of 345-kV and 147 miles of 230-kV transmission lines in the 2004–2013 time frame. The MRO-Canada existing transmission system is comprised of 5,411 miles of 230-kV and 130 miles of 500-kV transmission lines. MRO-Canada is planning to add 545 miles of additional 230-kV transmissions in the 2004–2013 time frame. MRO-U.S. and MRO-Canada have a total of 2,030 miles of HVdc lines.

MRO members continue to plan for a reliable transmission system, consistent with NERC Reliability Standards. Coordination of expansion plans in the region takes place through joint model development and study by the designated subcommittees of the MAPP Regional Transmission Committee and the MISO Expansion Planning Group. These committees include transmission owning members, transmission using members, power marketers, and state regulatory bodies. Together, these planning committees assess the adequacy of the transmission system within the MRO region.

In general, the MRO transmission system is judged to be adequate to meet firm obligations of the member systems, provided that the local facility improvements identified in both transmission plans are implemented. MRO continues to monitor the limiting flowgates within the region.

System stability operating guides involving the transmission facilities connecting Minneapolis-St. Paul to the Iowa and Wisconsin areas continue to manage congestion by limiting energy transfers from northern MRO to Iowa and Wisconsin. The Arrowhead-Weston 345-kV transmission line has been identified as a significant reinforcement to improve the overall performance of this interface. This line is expected to be in service in 2008. Information on the Arrowhead-Weston project can be found at: http://www.arrowhead-weston.com/.

Operations

MRO does not anticipate any major generation outages, transmission outages, or temporary operating measures that may impact reliability for any extended periods over the next ten years.

MRO member systems jointly perform interregional and intraregional seasonal operating studies under the direction of the Transmission Operations Subcommittee to coordinate real-time operations. Subregional operating review working groups have been formed to deal with day-to-day operational issues such as unit outages and to coordinate transmission system maintenance.

The Midwest Independent Transmission System Operator (MISO) energy market commenced on April 1, 2005. The market covers transactions in portions of Reliability*First*, MRO, and SERC across 15 states. From an MRO perspective, the market-to-nonmarket seam between the MRO members in MISO and those not in MISO creates additional operational complexity. MAPP and MISO continue to discuss issues related to implementing the Seams Operating Agreement (SOA) to coordinate transmission service on reciprocally managed flowgates and congestion management including transmission loading relief (TLR) avoidance procedures.

Assessment Process

The MRO Reliability Assessment Committee (RAC) is responsible for the MRO submittal to the NERC *Long-Term Reliability Assessment*. The MAPP Transmission Reliability Assessment and Composite System Reliability Working Groups jointly prepare the MRO *Ten-Year Reliability Assessment*, which is used as input by the MRO RAC. The MAPP Reliability Studies, Design Review, and Transmission Operations Subcommittees review MRO reliability from mid- and long-term perspectives and contribute to the MRO submittal to NERC.

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).

MRO-Canada Capacity and Demand

Figure 15: MRO-Canada Net Energy for Load

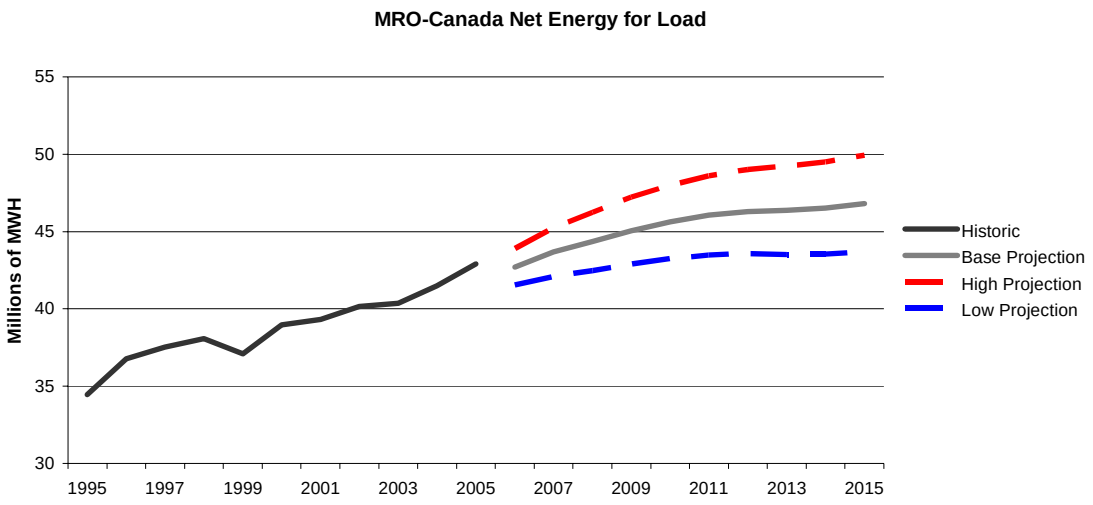


Figure 16: MRO-Canada Capacity Margins — Winter

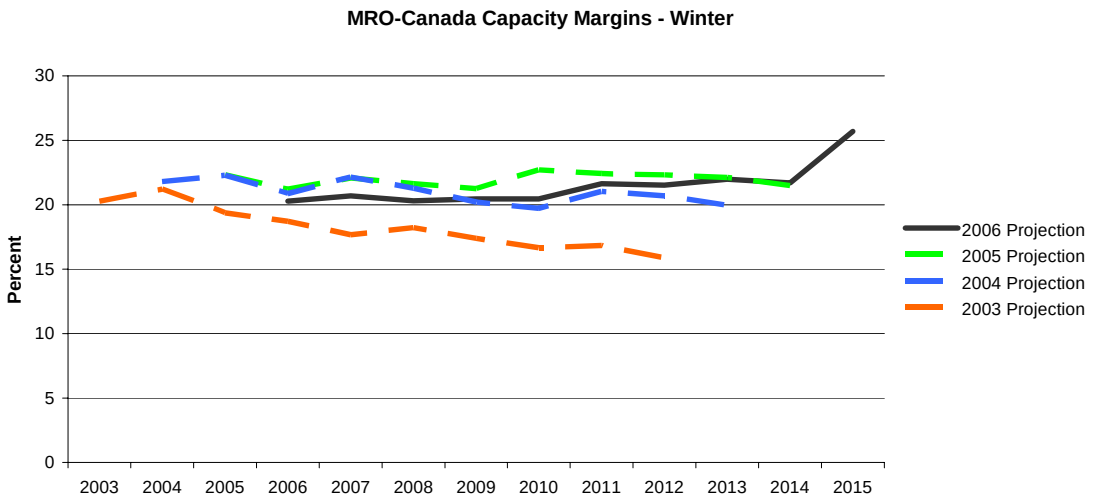
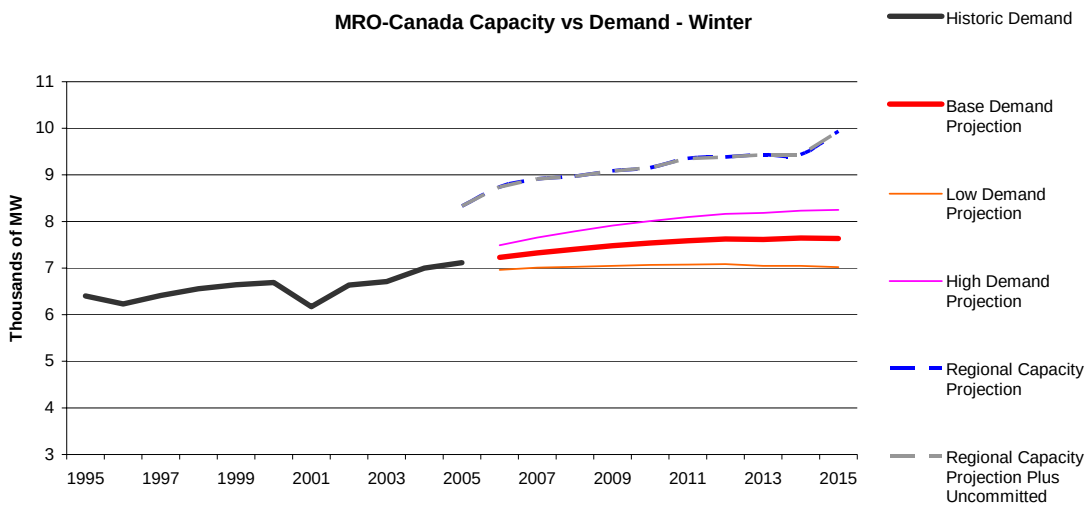


Figure 17: MRO-Canada Capacity Versus Demand — Winter



MRO-U.S. Capacity and Demand

Figure 18: MRO-U.S. Net Energy for Load

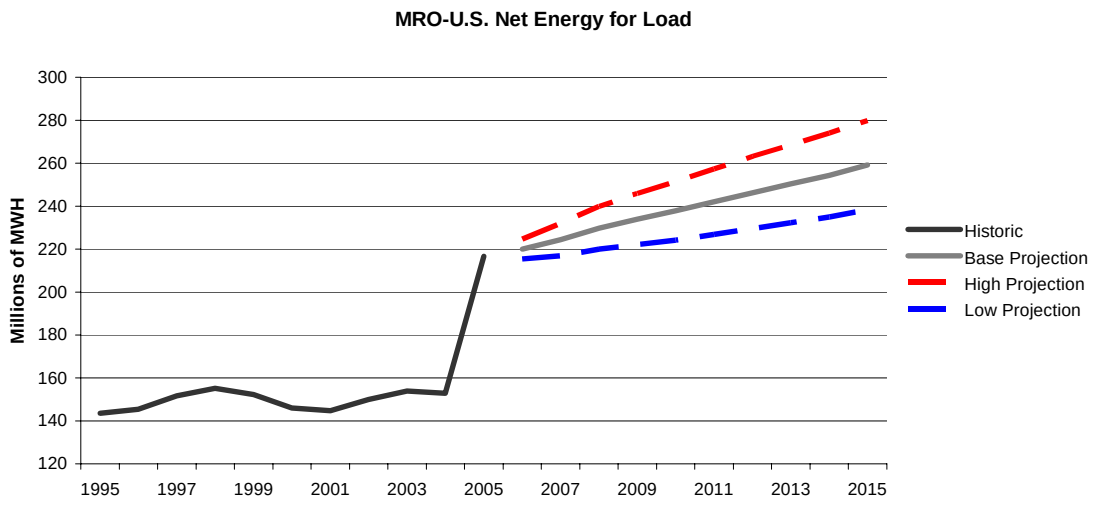


Figure 19: MRO-U.S. Capacity Margins — Summer

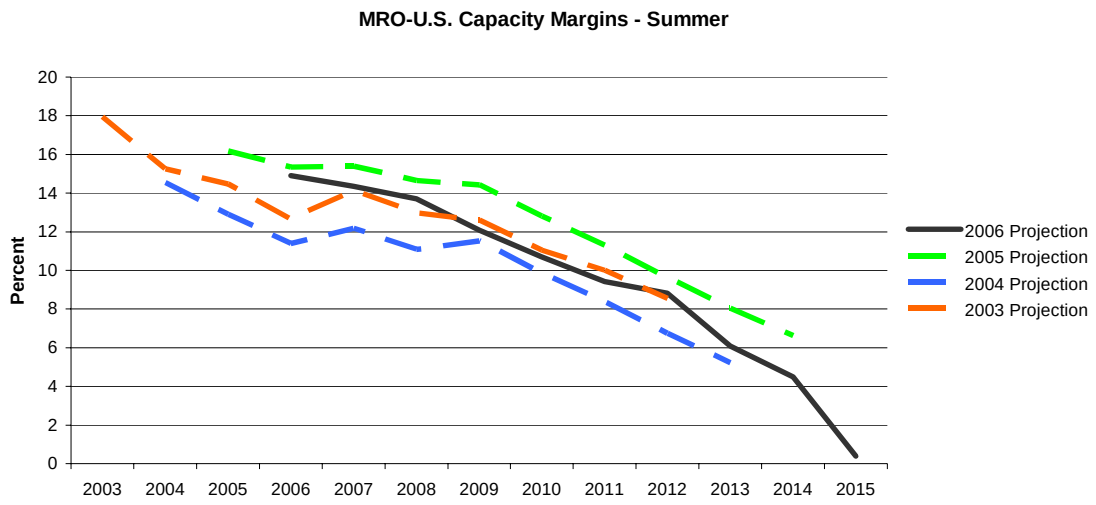


Figure 20: MRO-U.S. Capacity Versus Demand — Summer

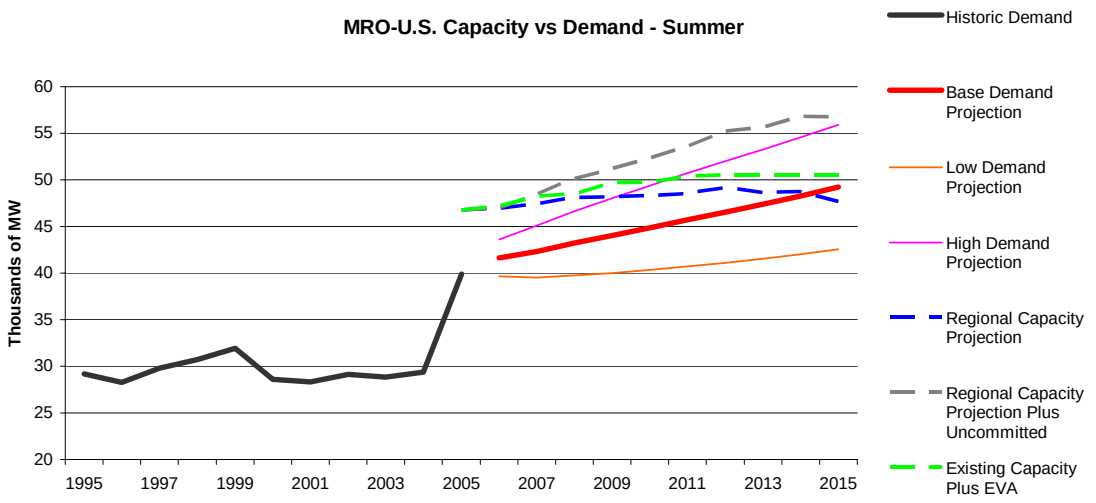


Figure 21: MRO-Canada Capacity Fuel Mix for 2005 and 2011

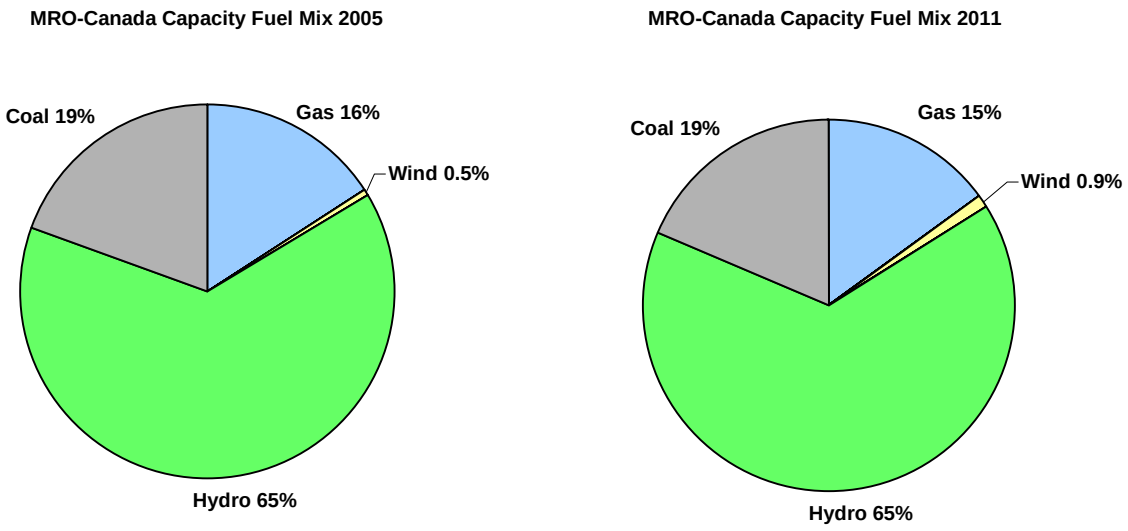
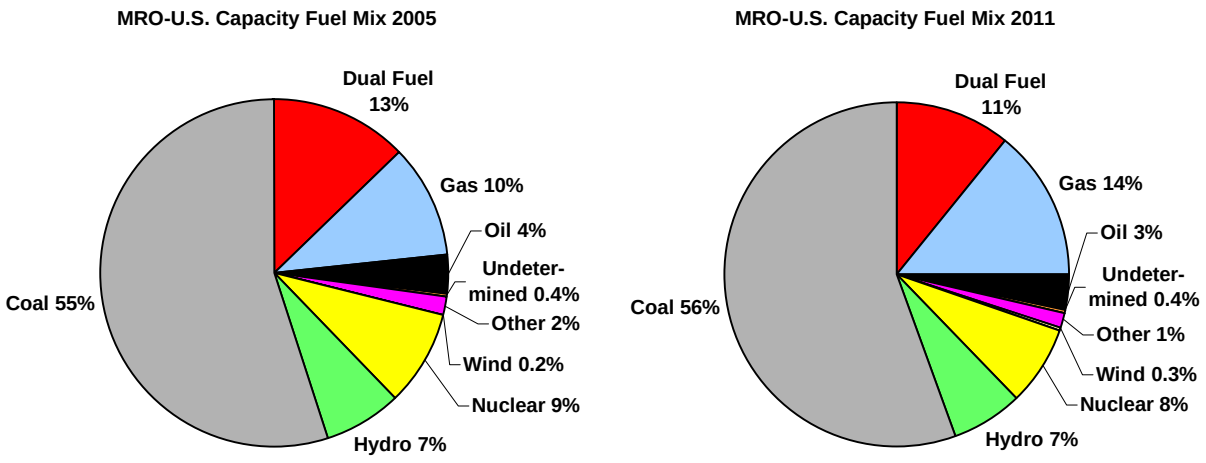


Figure 22: MRO-U.S. Capacity Fuel Mix for 2005 and 2011



NPCC

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

Due to their geographic and electrical diversity, the reliability of NPCC is monitored through the assessment of the five NPCC areas: the Maritimes (the New Brunswick System Operator, Nova Scotia Power Inc., the Maritime Electric Company Ltd., and the Northern Maine Independent System Administrator, Inc.), New England (the ISO New England Inc.), New York (the New York ISO), Ontario (the Independent Electricity System Operator) and Québec (Hydro-Québec TransÉnergie). Three of these areas are summer peaking in nature: New England, New York, and Ontario. The remaining two Canadian areas, the Maritimes, and Québec, are winter peaking systems.

Demand

The noncoincident peak demand for the five areas of NPCC is projected to be 142,181 MW by 2015, with an average growth of 1.4 percent. For the 2005–2014 study period, the noncoincident peak demand for the five areas of NPCC was projected to be 109,980 MW by 2014, with an average growth of 1.7 percent.

Energy

Net energy for load for the NPCC is projected to total 742,230 GWh in the calendar year 2015, with an average growth of 0.92 percent. For the 2005–2014 study period, net energy for load for the NPCC was projected to total 570,633 GWh in the year 2014, with an average growth of 1.23 percent.

Resources

NPCC has in place a comprehensive resource assessment program directed through NPCC Document B-08, *Guidelines for Area Review of Resource Adequacy* (http://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/b-08.pdf). This document charges the NPCC Task Force on Coordination of Planning (TFCP) to conduct periodic reviews of resource adequacy for NPCC. In undertaking each review, the TFCP will ensure that the proposed resources of each NPCC area will comply with Section 3.0, *Resource Adequacy - Design Criteria*, of NPCC Document A-02, *Basic Criteria for Design and Operation of Interconnected Power Systems* (http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/A-02.pdf). The resource adequacy criterion requires the following:

> "Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

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

- the ability of the area to reliably meet projected electricity demand, assuming the most likely load forecast for the area and the proposed resource scenario;

- the ability of the area to reliably meet projected electricity demand, assuming a high growth load forecast for the area and the proposed resource scenario;
- the impact of load and resource uncertainties on projected area reliability, discussing any available mechanisms to mitigate potential reliability impacts;
- the proposed resource capacity mix and the potential for reliability impacts due to the transportation infrastructure to supply the fuel;
- the internal transmission limitations; and
- the possibility of environmental requirements.

The resource adequacy review must describe the basic load model on which the review is based together with its inherent assumptions, and variations on the model must consider load forecast uncertainty. The anticipated impact on load and energy of demand-side management programs must also be addressed. If the area load model includes pockets of demand for entities, which are not members of NPCC, the area must discuss how it incorporates the electricity demand and energy projections of such entities.

Other supporting data which must be provided include the procedures used by the area for verifying generator ratings as well as a summary of forced outages, planned outages, partial deratings, etc., which would curtail available resources.

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

Fuel

Due to the diversity of fuel mix from area to area, the fuel requirements unique to each of the five NPCC areas are presented in the individual area discussions which follow.

Transmission

In a similar manner, the NPCC Task Force on System Studies (TFSS) is charged with conducting periodic reviews of the reliability of the planned bulk power transmission systems of each area of NPCC and the transmission interconnections to other areas, the conduct of which is directed through NPCC Document B-04, *Guidelines for NPCC AREA Transmission Reviews*. Each area is required to present an annual transmission review to the TFSS, assessing its transmission network four to six years in the future. Depending on the extent of the expected changes to the system, the review presented by the area may be one of three types: a comprehensive (or full) review; an intermediate (or partial) review; or an interim review.

A comprehensive review is a thorough assessment of the area's entire bulk power transmission system, and it must be conducted by each area at least every five years. The TFSS may require an area to present a comprehensive review in less than five years if changes in the area's planned facilities or forecasted system conditions warrant it.

In the years between comprehensive reviews, areas may conduct either an interim review, or an intermediate review, depending on the extent of the system changes projected for the area since its last comprehensive review. If the proposed system changes are deemed to be minor in nature, the area may conduct an interim review. In an interim review, the area provides a summary of the changes in planned facilities and forecasted system conditions since its last comprehensive review together with a discussion and assessment of the impact of those changes on the bulk power system.

If the system changes in the area since its last comprehensive review are moderate, or concentrated in a portion of the area's system, the area may conduct an intermediate review. An intermediate review covers all the elements of a comprehensive review, but the analyses may be limited to addressing only those issues considered to be of significance, considering the extent of the system changes.

Each transmission review includes a steady state assessment, a stability assessment, fault current assessments, and extreme contingency assessments. Further, special protection systems whose failure or misoperation could have a potential inter-area, or interregional impact require steady state and stability analyses of these consequences.

Actions in Response to the Power System Collapse of August 14, 2003

The NPCC assessment of the August 14, 2003 power system collapse, *NPCC August 14, 2003 Northeast Blackout Study*, was issued following approval by the NPCC Reliability Coordinating Committee (RCC) at its meeting of November 29–30, 2005. This report concluded exhaustive dynamic simulations conducted by the NPCC Working Group SS-38, replicating the August 14, 2003 sequence of events and the dynamic performance of the NPCC systems through the formation and collapse of the islands within NPCC. Upon approval of the report, the RCC proceeded to form the Blackout Recommendation Study Working Group (BRSWG) to develop a set of NPCC recommendations based on the conclusions presented in the NPCC blackout study. Linking its recommendations to the conclusions in the *NPCC August 14, 2003 Northeast Blackout Study*, specific charges were assigned to the NPCC task forces to conduct the work needed to address each recommendation. The BRSWG also completed a mapping of these recommendations against the blackout recommendations directed by the NERC Board of Trustees, the NERC Blackout Recommendation Review Task Force, and the U.S.-Canada Power System Outage Task Force to ensure no gaps or significant overlaps in the fulfillment of the recommendations. Several NPCC recommendations are similar, however, these NPCC recommendations address each item from an NPCC perspective rather than an overall industry view. Some of the key recommendations include the following:

- NPCC areas should review Type 1 and Type 2 special protection systems that rely on the indirect sensing of system conditions to reduce the possibility of their operating for conditions other than those for which they were originally designed.
- NPCC areas should complete the implementation of the incorporation of the 300 ms time delay on underfrequency load-shedding relays as recommended in the 2002 assessment of the NPCC underfrequency load-shedding program. Approved by the RCC, this project is in progress, and its completion is on schedule.
- The NPCC Task Force on System Studies should ensure that future assessments of the underfrequency load-shedding program include:
    - sensitivity studies to examine the impact of unexpected load or generation loss near the electrical center of unstable swings during island formation;
    - the continued pursuit of coordination between generating unit (generator, excitation system, and prime mover) protection systems and the underfrequency load-shedding program;
    - the simulation of island formation across area and regional boundaries, including the modeling of more extreme events;
    - an assessment of the impact of extremely low voltages on the performance of the underfrequency load-shedding program; and
    - the identification of large load areas within NPCC that are deficient in generation by more than 25 percent, that are susceptible to islanding and may accordingly require additional under frequency load shedding.

NPCC should continue to improve its modeling tools and data.

The status of the NPCC response to all recommendations generated by the blackout of August 2003 may be followed by accessing http://www.npcc.org/blackout.asp?Folder=CurrentYear.

Operations

Reliable operations within NPCC are directed through the five reliability coordinators of NPCC. Each of the NPCC areas also serves as a NERC reliability coordinator for the following geographic areas:

Entity Serving as NERC Reliability Coordinator	Reliability Coordinator Footprint
New Brunswick System Operator (NBSO)	Provinces of New Brunswick, Nova Scotia, and Prince Edward Island; the Northern Maine Independent System Administrator, Inc.
ISO New England Inc.	States of Maine, Massachusetts, Vermont, New Hampshire, Connecticut, Rhode Island
New York ISO	State of New York
Independent Electricity System Operator (IESO)	Province of Ontario
Hydro-Québec TransÉnergie	Province of Québec

Within each area, the respective reliability coordinator assumes the authority and responsibility to immediately direct the redispatch of generation, the reconfiguration of transmission, or (if necessary to return the system to a secure state) the shedding of firm load. Coordination in the daily operation of the bulk power system is assisted through enhanced communications and heightened awareness of system conditions and mutual assistance during an emergency or a potentially evolving emergency. The reliability coordinators of NPCC conduct conference calls daily and weekly to identify and assess emerging system conditions. Procedures are in place to initiate emergency conference calls whenever one or more areas anticipates a shortfall of capacity or anticipates the implementation of operating measures in response to a system emergency.

The NERC standards, together with the Regional Criteria, Guides, and Procedures, establish the fundamental principles of interconnected operations among the NPCC areas.

NPCC Document A-03, *Emergency Operation Criteria*, presents the basic factors to be considered in formulating plans and procedures to be followed in an emergency or during conditions which could lead to an emergency, in order to facilitate mutual assistance and coordination among the areas. The criterion establishes seven basic objectives in formulating plans related to emergency operating conditions, including the avoidance of interruption of service-to-firm load, minimizing the occurrence of system disturbances, containing any system disturbance and limiting its effects to the area initially impacted, minimizing the effects of any system disturbances on the customer, avoiding damage to system elements, avoiding potential hazard to the public, and ensuring area readiness to restore its system in the event of a major or partial blackout.

NPCC Document A-06, *Operating Reserve Criteria*, defines the necessary operating capacity required to: meet forecast load; accommodate load forecasting error; provide protection against equipment failure, which has a reasonably high probability of occurrence; and provide adequate regulation of frequency and tie-line power flow. The NPCC *Operating Reserve Criteria* require two components of operating reserve. The ten-minute operating reserve available to each area shall at least equal its most severe first contingency loss. The 30-minute operating reserve available to each area shall at least equal one-half its most severe second contingency loss.

Various operating guidelines and procedures complement the NPCC criteria by providing the system operator with detailed instructions to address such topics as the depletion of operating reserve, capacity

shortfalls, the sharing of operating reserve, line-loading relief, declining voltage, measures to contain the spread of an emergency, light-load conditions, the rating of generating capability, the consequences of a solar magnetic disturbance, procedures for communications during an emergency, and the coordinated restoration of the systems following a partial or total blackout.

NPCC also participates in the seasonal Reliability*First* Corporation-Northeast Power Coordinating Council (RFC-NPCC) operating assessments, formerly conducted under the direction of the MAAC-ECAR-NPCC (MEN) and VACAR-ECAR-MAAC (VEM) study committees.

Assessment Process

The NPCC Reliability Assessment Program (RAP) brings together the efforts of the Council and its members in the assessment of the reliability of the bulk power system. The Reliability Coordinating Committee (RCC), as the primary technical arm of the Council, directs the RAP and monitors the compliance with all aspects of the program. The RCC is served by the five NPCC task forces, which address the major disciplines of planning, operations, protection, and communications as follows:

- Task Force on Coordination of Operation
- Task Force on Coordination of Planning
- Task Force on Infrastructure Security and Technology
- Task Force on System Protection
- Task Force on System Studies

The task forces in turn develop and administer the documents, which define reliable operation and planning within NPCC, and with which compliance is mandatory on the part of all NPCC members. The assessment of transmission reliability and resource adequacy is directed to the five NPCC areas.

Maritimes

The Maritimes area is a winter-peaking area that includes the New Brunswick System Operator (NBSO), Nova Scotia Power Inc. (NSPI), Maritime Electric Company Ltd. (MECL), and the Northern Maine Independent System Administrator, Inc. (NMISA). MECL supplies the province of Prince Edward Island. The New Brunswick Electricity Act restructured the electric utility industry in New Brunswick and created the NBSO, the reliability coordinator for the Maritimes area.

Demand — The noncoincident peak demand for the Maritimes is projected to be 6,364 MW by 2015, with an average growth of 0.8 percent. For the 2005–2014 study period, the noncoincident peak demand for the Maritimes area was projected to be 6,429 MW by 2014, with an average growth of 1.4 percent.

In the *2005 Maritimes Area Interim Review of Resource Adequacy*, compliance with the NPCC Resource Adequacy Criterion was evaluated using a load forecast uncertainty of 4.6 percent, which represents the historical standard deviation of load forecast errors based upon the four year lead time required to add new resources.

Energy — In 2005, the actual energy consumption in the Maritimes was 29,398 GWh, and this was 3.3 percent below forecast primarily due to warmer than expected temperatures in the winter months when demand is highest. Net energy for load is projected to total 33,553 GWh in the calendar year 2015, with an average growth of 1.6 percent. For the 2005–2014 study period, net energy for load was projected to total 33,908 GWh in the year 2014, with an average growth of 1.6 percent.

Resources — The NBSO and NSPI individually apply a capacity-based criterion of 20 percent in determining their required reserve, while MECL uses 15 percent. NMISA does not apply a capacity-based criterion beyond the NPCC reliability criterion. Since NBSO and NSPI comprise about 94 percent

of the Maritimes area load, this effectively produces a required reserve of 20 percent for the Maritimes. This reserve requirement is to accommodate both peak demand uncertainty and generation availability uncertainty.

The planned refurbishment of the 635 MW Point Lepreau nuclear facility in New Brunswick will require an outage of 18 months, beginning in April 2008, with completion scheduled for November 2009. Due to this outage, the Maritimes area will require 20 MW of additional capacity to meet the NPCC resource adequacy criterion. Plans for replacement capacity to accommodate this refurbishment are still being evaluated by NB Power.

A sale of 200 MW of firm capacity will be sold to Québec until 2010/11. The Maritimes does not depend upon outside purchases to meet demand requirements.

There are currently no firm plans for merchant and/or uncommitted capacity over the next ten years.

Fuel — Fuel supply will be adequate to meet expected electric demand. This is accomplished with firm fuel contracts, as well as on-site storage facilities.

The Maritimes does not consider fuel-supply interruptions in the regional assessment. The Maritimes has a diversified mix of resources such that the reliance on any one type or source of fuel is reduced. In addition, fuel storage facilities located at each plant are sufficient to permit the continued operation of plants during short duration interruptions to the fuel supply. During longer-term interruptions, this fuel storage capability affords the opportunity to secure other sources of supply or, at some plants, to switch to a different fuel. No fuel delivery problems are anticipated during the projected peak demand period. Mitigation procedures include the ability of some plants to switch to a different fuel. Extremes of summer weather do not impact fuel availability since the Maritimes area is a winter-peaking system. Extreme weather conditions at other times of the year are not expected to have any impact on the Maritimes area's fuel supplies for generating facilities. Sufficient on-site fuel reserves are maintained for all fossil-fired generation. All plants which are equipped to burn Orimulsion®, for which Venezuela is the single source supplier of the fuel, can be switched to burn oil. Although the reliance of electric generation on the natural gas infrastructure is increasing, only about 8 percent of the generators in the Maritimes use natural gas.

Transmission — No transmission constraints were identified within the Maritimes area. Construction of a second 345-kV interconnection between New Brunswick and New England is scheduled to be in service by December 2007, connecting Point Lepreau, New Brunswick to Orrington, Maine. As a result of this project (including series and shunt capacitors in Maine), the maximum transfer capability between New Brunswick and New England is increased from 700 MW to 1,000 MW, and the import capability from New England to New Brunswick is expected to be raised from 100 MW to 400 MW. This second interconnection also significantly improves the reliability of the Maritimes system, since loss of either of the two interconnections to New England will no longer result in the separation of the Maritimes from the Eastern Interconnection.

The "Loss of L3001" special protection system (SPS) senses power and frequency inputs to detect conditions consistent with a system separation south of the New Brunswick-New England border. During the power system collapse of August 14, 2003, the Keswick-Orrington 345-kV interconnection between New Brunswick and New England experienced a power swing coincident with a rise in system frequency, triggering the SPS and rejecting 380 MW of generation in the Maritimes. While the SPS responded correctly for the power and frequency conditions observed, the SPS operated while the Maritimes and New England were connected to the Eastern Interconnection. Although the SPS performed according to its design, subsequent analysis by the NPCC Working Group SS-38 showed that its inadvertent operation was unnecessary. As a result of this finding, revisions will be made to the SPS associated with the second

New Brunswick-New England interconnection. The Loss of L3001 SPS will be replaced by a more robust "Maritimes Islanding SPS," which will directly sense the status of selected circuit breakers in Maine, indicating separation of the Maritimes from New England. Design details are currently under review by the appropriate NPCC task forces.

Operations — The addition of the second 345-kV tie discussed above between New Brunswick and New England will improve system reliability, stability, and efficiency in addition to expanding competition and electric energy transfers.

The outage due to the refurbishment of the 635 MW Point Lepreau nuclear generation station (April 2008 to October 2009) creates a 229 MW capacity deficiency for the Maritimes. Plans for replacement capacity to accommodate this refurbishment are still being evaluated by NB Power.

No local environmental and/or regulatory restrictions that could curtail the availability of capacity in the Maritimes area are expected. However, the Kyoto Protocol, ratified by the g`overnment of Canada, calls for a 6 percent reduction from the 1990 levels of greenhouse gas emissions to be achieved between 2008 and 2012. Initiatives to achieve this reduction may include a reduction in electric energy exports from the Maritimes area. Renewable energy targets announced by governments within the Maritimes area could result in the addition of about 1,000 MW of wind generation for the Maritimes.

New England

Demand — This year's summer peak forecast ten-year compound annual average growth rate has increased to 1.9 percent from 1.5 percent following a change in the forecasting methodology, resulting in generally higher summer peak forecasts when compared with previous long-term forecasts. (Details on the load and energy forecasting methodology used by the ISO-NE, together with data, may be found at http://www.iso-ne.com/trans/celt/fsct_detail/index.html.)

The summer peak forecast distribution is based on 30 years of weather and peak data. Using this weather and peak data, a distribution of peak loads is calculated to show the peak load forecasts associated with a probability that the forecast would be exceeded. (Further information on the load forecast may be found in the *2006–2015 Forecast Report of Capacity Energy Loads and Transmission—April, 2006*, available at http://www.iso-ne.com/trans/celt.)

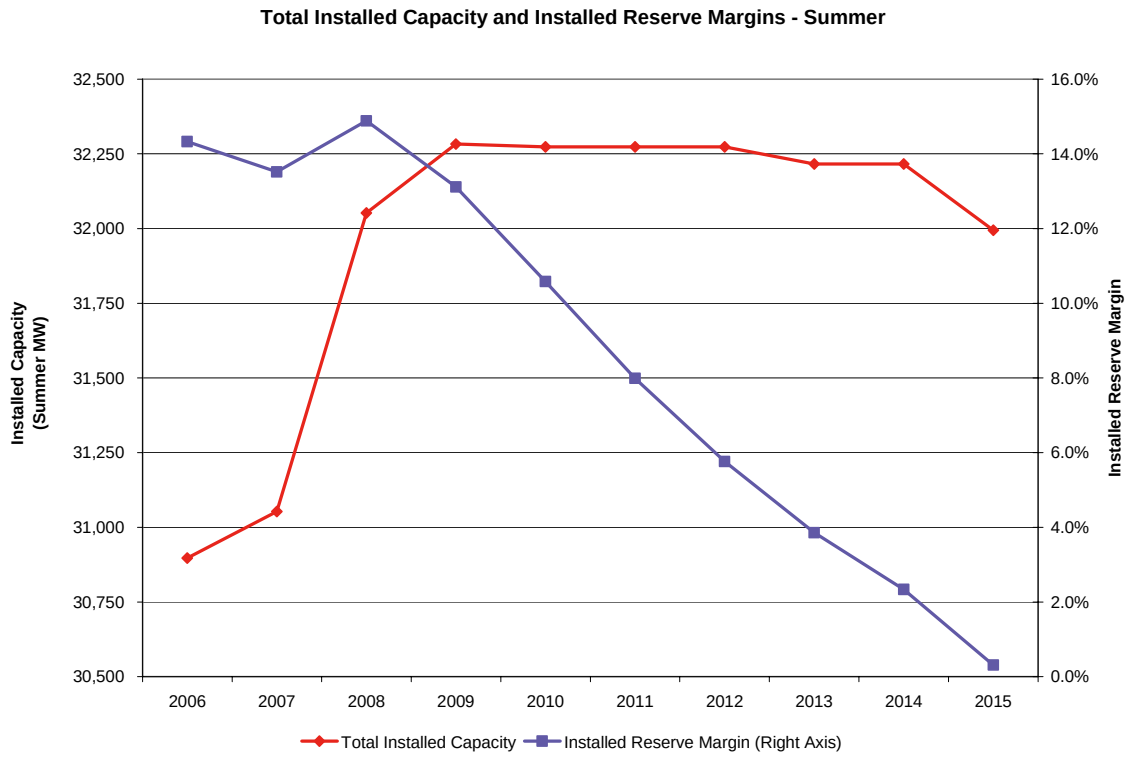
A detailed analysis of each summer's daily peaks and weather is carried out to quantify the relationship between peak and weather, and changes to that relationship. The maximum exposure under the 90/10 forecast over the ten-year study period is as follows:

Year	90/10 Load Forecast in MW
2006	28,785
2007	29,180
2008	29,775
2009	30,465
2010	31,160
2011	31,910
2012	32,580
2013	33,125
2014	33,620
2015	34,065

***Energy* —** The projected 1.3 percent ten-year compound annual growth rate for net annual energy did not change significantly.

***Resources* —** Figure 30 (below) illustrates the total installed capacity as well as the installed reserve margins forecasted for the study period.

Figure 23: Total Installed Capacity and Installed Reserve Margins — Summer



Installed reserve margins will be declining throughout the study period from a high of 15 percent in 2008 to almost 0 percent in 2015. The installed reserve margins reflect firm capacity purchases of approximately 400 MW per year through 2012, approximately 330 MW purchase in 2013–2014, and approximately 110 MW in 2015. Generating unit retirements are not assumed throughout the study period and new generation totaling approximately 1,390 MW (these capabilities include projects that have received proposed plan approval) is assumed to commercialize by the end of 2009.)

Last year, projected installed reserve margins were 19.4 percent in 2005 and declined through the study period to 8.5 percent in 2014. The primary factors associated with the decline from last year's forecasted reserve margins are the updated load forecast coupled with a lower installed capacity value due to deactivations/ratings of existing capacity and lower firm capacity purchases.

With respect to the regional requirement, ISO-NE anticipates that New England will meet the NPCC resource adequacy criterion of one-day-in-ten-years loss-of-load expectation through 2008 assuming forecasted loads and capacity materialize and 2,000 MW of tie reliability benefits are available. This is made up of 600 MW from New York, 1,200 MW from Hydro Québec, and 200 MW from New Brunswick. Existing transfer capability study results indicate that sufficient transfer capability is in place with surrounding areas to receive this assistance when needed. New capacity will be needed beyond that year in order to meet the reliability criterion. This assessment is based on estimated requirements calculated in the 2006 Regional System Plan.

No long-term sales to regions outside of New England were known as of January 1, 2006. When analyzing the resource adequacy situation of New England, only firm long-term capacity purchases and sales are included in the assessment. For the 2006 assessment, it is forecasted that ISO-NE will be a net importer of approximately 400 MW per year through 2012. This net import will decline to approximately 330 MW in 2013–2014, and to approximately 110 MW in 2015. These long-term capacity purchases are included as capacity when calculating the installed reserve margins for New England.

To meet NPCC criteria, and assuming 2,000 MW of tie reliability benefits are available from neighboring control areas, approximately 170 MW are needed in 2009, increasing annually and requiring a total of 4,300 MW by 2015.

Fuel — ISO-NE assesses the potential for fuel-supply interruptions and their impacts on system reliability in the annual Regional System Planning and when additional analyses are deemed necessary. It is anticipated that no constraints in fuel supply or delivery to the generators will occur during the summer peak load seasons. During extreme summer periods, no fuel supply or delivery constraints to New England generators is expected.

During extreme cold weather in the winter, when the demand for electricity and natural gas peak coincidently, the ISO-NE has special operating procedures that have been developed to mitigate possible short-term loss of operable generating capacity due to fuel unavailability. The ISO-NE is mindful of the potential for fuel constraints during peak load periods and is proactive in ensuring the reliability of the power system.

ISO-NE is encouraging the maximization and sustainability of existing dual-fuel capability as well as expand dual-fuel capability to gas only units. The study, *Dual-Fuel Generating Capacity and Environmental Constraints Analysis – Interim Report*, identified many gas-fired units had air permits to burn limited amounts of liquid fuel oil during emergency periods. However, in some cases, these air permits were ambiguous about when these units could actually burn oil. Furthermore, many of these units with air permits to burn liquids had not installed the necessary hardware (burner systems, software control, etc.) or support infrastructure (on-site storage and fuel handling) to facilitate dual-fuel operation.

ISO-NE has worked (and continues to) with regional air regulators to review existing power plant operating permits with respect to clarifying existing language and incorporating exemption clauses that will allow limited or extended oil-burning operation only during periods when the electric power system is in an abnormal state (invocation of Emergency and/or Cold Weather Operating Procedures) or when the regional natural gas and oil supply and/or delivery systems have been constrained or curtailed due to force majeure type events. ISO-NE is currently working to assess the true capability and sustainability of dual-fuel operation across the generation fleet, with emphasis on determining the exact amount and location of dual-fuel capacity required to sustain reliable winter operations.

Transmission — The 2005 Regional System Plan identifies the region's needed transmission improvements and provides a roadmap for identifying the system's needed improvements in the long term. The New England region has 272 transmission projects in various stages of planning, construction, and implementation with a total cost of about $3 billion. ISO-NE and the transmission owners collaboratively conducted the studies that support these projects. These projects are required over the next ten years to ensure local-area and system-wide reliability in accordance with NERC, NPCC, and ISO-NE planning criteria, and to facilitate the future operation of the system. These upgrades may be needed: to address electrical performance problems, such as those related to voltage or stability; to serve growing loads; or as a backstop for market solutions to system needs. The transmission improvements in load/generation pockets will reduce local-area and system-wide dependency on the generators to provide either economic operating reserves or reserves based on reliability needs and the need to commit generating resources out of merit.

Six of the 272 transmission projects are major and have significant reliability impacts on the region. These projects include the Northwest Vermont Reliability Project, the Northeast Reliability Interconnect Project, the Southwest Connecticut Reliability Project (Phase 1 and Phase 2), the Southern New England Reinforcement Project, and the NSTAR 345-kV Transmission Project. (Detailed information on the New England transmission projects can be found in the *ISO New England Regional System Plan-October 20, 2005*.)

A number of transmission constraints limit the efficient transportation of power across the network, and in some cases these limitations jeopardize the reliability of the local system. The significant network constraints are described below.

Maine-New Hampshire

Transmission constraints between Maine and New Hampshire limit the transfer of power from Maine into New Hampshire. This interface is impacted by stability and thermal limits. Voltage levels are often a concern in this area. These limits are also sensitive to load levels. As the load in New England increases, this restriction could further compromise New England's ability to meet its LOLE criteria as early as 2009.

A number of projects are under way to address local reliability needs that will also impact the capability of this interface. These projects are in various stages of development and approval. Most recently approved was the Y-138 Project, scheduled for 2008, which closes a normally open tie between western Maine and New Hampshire. Additional projects which are in progress are the addition of circuit breakers, scheduled for 2006 and 2008, respectively, at Deerfield and Buxton, which removes limiting stuck breaker contingencies, looping the Buxton-Scobie 345-kV line into the Deerfield Station, and the addition of new autotransformers which will provide much needed voltage support to the 115-kV lines from southern Maine into the seacoast area of New Hampshire.

Vermont

The power system serving the state of Vermont is primarily designed to serve native load, and as such it only has four bulk power system buses within the state (West Rutland 345 kV, Coolidge 345 kV, Vermont Yankee 345 kV, and Vermont Yankee 115 kV). Therefore the Vermont system is limited in its ability to move power into and within the state to serve its own load. This problem is exacerbated by the fact that the state of Vermont has only one large generation station (Vermont Yankee), and, since the plant is located at the southernmost end of the state, its capacity output loads the Vermont transmission system as if it were an import from outside the state. The most limiting contingency for Vermont has been the outage of the Highgate HVdc source. Further, the outage of any major line in Vermont could initiate localized undervoltage load shedding to alleviate voltage constraints.

The Northwest Vermont Reliability Project includes a new 345-kV line within the state, the addition of new devices to provide reactive support throughout the state, and an additional phase angle regulator to help control flows. This project is currently under construction.

Connecticut/East-West

The Connecticut system is limited in its ability to transfer power into the state to serve its own load. While it has a significant amount of internal generation, the total amount of generation is insufficient when combined with imports to reliably serve load. The most significant contingencies in the state are the outage of the Millstone unit 3 generation (~1,200 MW) or one of the three 345-kV tie lines into the state. A long-term outage of either of these compromises reliability in the state of Connecticut. The east-west interface follows approximately the Vermont border down through central Massachusetts to the Connecticut border. This interface can limit economic transfers of power from the east to load centers in the west. Under heavy load periods with generation outages in the west, this interface could affect the reliability of the western portion of New England.

A working group has been formed which will address these issues, as well as other southern New England issues. This working group has performed exhaustive testing of numerous possible system configurations and should be selecting a preferred alternative by the fall of 2006. Implementing the resulting plan will also improve the east-to-west New England transfer capability at the same time.

Southwest Connecticut
The southwest Connecticut system is served only by 115-kV and 138-kV transmission lines and internal generation which can have significant interdependencies (both thermal and short circuit) that can limit its operation. In addition to the thermal constraints which prevent the movement of power into southwest Connecticut, transmission limitations are also preventing the movement of large amounts of power within the area.

In addition to a number of smaller projects that have increased reactive support in and around southwest Connecticut, construction has already begun on two large 345-kV installations to build a 345-kV loop through the area. The first portion of this installation is expected to be in service by the end of 2006, while the second piece is expected prior to the end of 2009. These two projects should remove the generation interdependencies internal to the area, and will also increase the import capability into the area. In addition to the two 345-kV projects, a smaller 115-kV project extends new circuits from one of the new 345-kV substations to the load centers in the farthest corner of the area.

Boston
The Boston area is limited by imports into and within the area and is reliant upon internal generation. An outage of one of the major 345-kV lines feeding the area, or the outage of a significant generator could compromise the ability to reliably serve load in this area. Internal loss of source concerns are amplified by the possibility of a simultaneous loss of both Mystic units 8 and 9 (~1,600 MW), which has already occurred in real-time operations.

A number of projects are under way to relieve some of the constraints that limit Boston imports. The Ward Hill project provides significantly more transformation to the 115 kV at this location and upgrades lines which travel toward Boston. Additionally, a project is under way to add three new 345-kV cables into downtown Boston. The first stage of this project, which adds two of the three cables, is expected to be in service during the summer of 2006.

A detailed listing of all projected new facilities proposed to enhance transmission reliability in New England can be found at: http://www.iso-ne.com/trans/rsp/index.html.

Operations — The construction of new transmission projects, and any necessary outages of existing transmission or generation equipment that may be required, is closely coordinated with the ISO-NE, to avoid adverse impacts to the reliability of the system.

During the study period, it is anticipated that additional environmental requirements and regulations will be put on generators in New England. The ISO-NE is mindful of these regulations and assesses their possible impacts on system reliability. If generators in New England are required to retrofit their facilities to meet these regulations, the ISO-NE will closely coordinate the maintenance needs of these generating units to assure that system reliability is maintained at all times.

New York

Demand — The New York area is a summer-peaking system, and summer peak demands are expected to grow at an average rate of 0.9 percent, through 2015. This compares with 0.9 percent growth projected in the 2004–2015 assessment conducted by the RAS in 2005.

The forecast developed by the NYISO is based on historical weather-normalized loads provided by the transmission owners of New York State. At forecast load levels, a one-degree increase in the combined temperature humidity index, or CTHI, (an index that weights dry bulb by 60 percent and dew point by 40 percent, and includes a lag structure) above the design value of 81.31 will result in about 500 MW of additional load.

Energy — Energy consumption is forecast to grow at an average annual rate of 0.8 percent through 2015. This compares with 0.8 percent growth projected in the 2005–2014 assessment conducted by the RAS in 2005.

Resources — The New York State Reliability Council (NYSRC) has determined that an 18 percent installed reserve margin for the New York control area (NYCA) is required to meet the NPCC and more stringent NYSRC resource adequacy criterion. As a conservative assumption, the establishment of the 18 percent installed reserve margin requirement for New York does not rely on external ICAP purchases. Up to 2,000–2,400 MW of assistance through tie benefits from New York's neighboring control areas is also available.

Given current demand projections, New York would need the addition of 4,030 MW of new resources in order to meet a projected 18 percent level through 2015. This projection assumes the continuation of the current level of external purchases of approximately 2,500 MW and the continuation of special case resources (SCRs) of approximately 1,080 MW. SCRs are loads capable of being interrupted, and distributed generators rated at 100 kW or higher, that are not directly telemetered. SCRs are installed capacity (ICAP) resources that only provide energy/load curtailment when activated in accordance with the NYISO Emergency Operating Manual.

It is anticipated that the resources necessary to meet this projected requirement would be procured through the NYISO ICAP market. Currently, new capacity totaling 2,940 MW is under construction in New York. The generation currently under construction in conjunction with the approximately 2,500 MW of allowable external purchases will be sufficient for New York to meet an 18 percent reserve margin through 2015 even if no new projects are proposed.

Studies are currently in progress to assess the deliverability of this capacity within New York State and the New York City-Long Island zones.

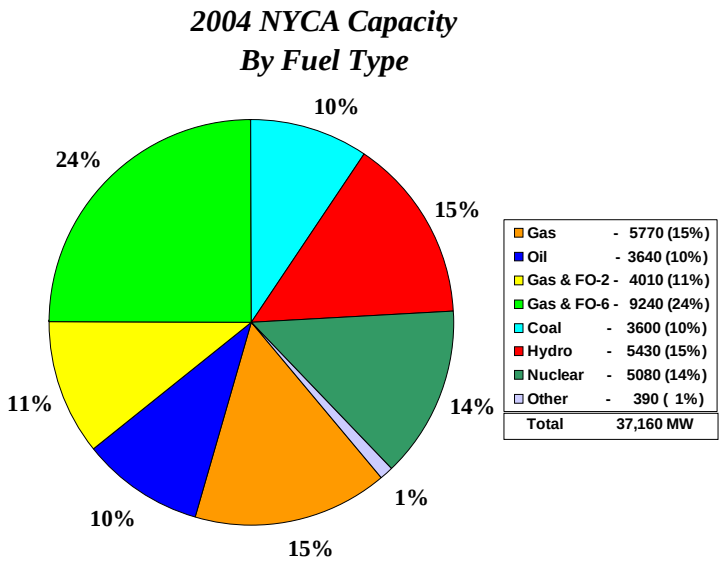
In addition to the above statewide requirement, the New York ISO imposes locational capacity requirements on load-serving entities located within New York City and Long Island due to their geography, as described in the *Locational Installed Capacity Requirements Study of March 2006*. The load-serving entities within these localities must procure a percentage of their capacity requirement from resources located within the geographic boundaries of that locality. The New York City locational capacity requirement is 80 percent of the demand level, and the locational capacity requirement is 99 percent of the demand level within Long Island.

Long Island will meet its projected demand growth with 115 MW of SCRs and the addition of the Cross Sound Controllable Line (330 MW). At the current locational requirement level, over 500 MW of additional new capacity will be needed by 2015 in order to meet projected load growth. The 660 MW Neptune dc line to New Jersey will give Long Island load-serving entities access to sufficient capacity to meet those obligations.

New York City has recently met its locational capacity requirement by the addition of a 500 MW combined-cycle plant. If the projected locational requirements stay at 80 percent,the plants currently under construction, along with SCRs, would be adequate to meet the projected load growth through the year 2015.

***Fuel* —** Figure 31 depicts New York's resource capacity mix by fuel type for the year 2004 on an installed capacity basis.

Figure 24: 2004 NYCA Capacity by Fuel Type



Planned Resource Capacity Mix							
Month of July	**Coal %**	**Gas and Oil %**	**Gas Only %**	**Hydro %**	**Nuclear %**	**Oil Only %**	**Other %**
2006	9.0	46.9	5.9	14.8	12.9	9.0	1.6
2007	7.9	48.4	5.7	14.3	12.8	8.7	2.2
2008	6.9	48.2	5.9	14.7	13.1	9.0	2.2
2009	6.9	48.2	5.9	14.7	13.1	9.0	2.2
2010	7.0	48.0	5.9	14.8	13.2	9.0	2.2

The above table shows the projected installed capacity resource mix from 2006 through 2010. The "other" category includes wind power, resource recovery, wood burning, and other fuels. For the next five years, resources fueled by natural gas will meet all of the growth in projected energy consumption. Except for wind energy, no new resources employing other fuels are expected to be added in the planning period.

New York State has a potential for a natural gas shortage in the winter. This could cause natural gas-fired units to burn other fuels or curtail operations. If unit operation curtailment due to fuel unavailability occurs in load pockets, generation from other areas would need to help meet demand, causing heavier loading on the existing transmission system. Many of the dual-fired units are the larger older steam units located in load pockets and would impact reliability needs in multiple ways if retired. The real challenge on a going-forward basis will be to maintain the benefits that fuel diversity, in particular dual-fired fuel capability, provides today. This will be especially critical in New York City and Long Island, which are entirely dependent on oil- and gas-fired units many of which have interruptible gas transportation contracts. In terms of operational strategy, the NYSRC has adopted the following local reliability rule:

I-R3. Loss of Generator Gas Supply (New York City & Long Island)

"The NYS Bulk Power System shall be operated so that the loss of a single gas facility (i.e., pipeline or storage facility) does not result in the loss of electric load within the New York City and Long Island zones."

NYSIO categorizes generation capacity fuel types into three supply risks: low, moderate, and high.

The greatest risk to fuel-supply interruption occurs during the winter months when both natural gas and heating fuel oils are competing to serve electrical and heating loads. Fortunately in New York, peak electrical loads occur during the summer months when demand is nearly 7,000 MW greater than the winter peak. As such, New York can meet the winter peak of roughly 25,000 MW with sufficient generation without exposure to significant fuel risks. Even with a forced outage rate of 10 percent,sufficient generation in the low to moderate fuel risk categories is in place to meet the winter electrical peak of 25,500 MW. This would leave a margin of nearly 4,000 MW or 14 percent of the total capacity characterized by low to moderate fuel risk.

Transmission — Based on the present load forecast, planned transmission facilities, and projected generation resources, including proposed generation additions and associated transmission upgrades, the New York bulk power transmission system is judged to be adequate through 2015.

Significant transmission and generation projects currently being proposed include the following:

Major NY Transmission and Generation Projects	Status	In-Service Date
Replace Norwalk Harbor — Northport Cable	S	2008
Niagara Upgrade (325 MW hydro) (12 units completed, remaining 1 unit to be completed 12/2006	C	2006
Bethlehem Energy (Albany Steam, 400-730 MW repowering)	I/S	2005
Poletti, Astoria (500 MW)	C	2006
KeySpan, Spagnoli Road, LI (250 MW CC)	S	2008-09
Calpine Wawayanda Energy Center, Middletown (500 MW)	S	2008
Reliant Astoria Repowering — Phase 1 (367 MW)	S	2010
Mirant, Bowline Pt. 3, W. Haverstraw (750 MW)	S	2008
SCS Energy, Astoria (1000 MW CC)	C	2006-07
ANP Brookhaven Energy, LI (580 MW)	W	N/A
Glenville, Rotterdam (540 MW)	S	2008
Besicorp, Reynolds Road (660 MW)	S	2007
Reliant Astoria Repowering — Phase 2 (173 MW)	S	2011
PSEG Power Radial Line to NYC (550 MW)	S	2008
TransGas Energy, New York City (1100 MW)	S	2008-09
PG&E/ Liberty Generation Connection to New York City (400-600 MW)	S	2007
RG&E 4th Station 80 345/115 kV Transformer and Other Upgrades	S	2008
Flat Rock Wind Generation Project (240-300 MW)	S	2005-06
Mott Haven 345 kV Substation	S	2007
Sprainbrook-Sherman Creek 345 kV	S	2007
Blenheim-Gilboa Uprate (120 MW Pumped Storage) (1 unit (30 MW) each year starting Fall 2006 through Spring 2010)	S	2007

Status Key:

P – Proposed
S – Study is under way or complete
C – Under construction
I/S – In Service
O/S – Out of Service
R – Retired

Terminals		Miles	Year	Voltage	No. of Circuits
Duffy Ave Convertor Station	PJM	65.000	2007	500	1
Dunwoodie	Sherman Creek	7.8	2005	138	1
Mott Haven	Dunwoodie	9.989	2007	345	2
Mott Haven	Rainey	4.083	2007	345	2
Sprain Brook	Sherman Creek	10	2007	345	1
Newbridge Rd	East Garden City	4	2007	138	1
Newbridge Rd	Ruland Rd	9.1	2007	138	1
Duffy Ave Convertor Station	Newbridge Rd 345kv	1.7	2007	345	1
Newbridge Rd 345kv	Newbridge Rd 138kv	-	2007	-	2
Station 80	Station 82/Mortimer	3.500	2007/2008	115	1
Station 80	Station 82/Mortimer	3.500	2007/2008	115	1
Station 82	Station 67	2.400	2007/2008	115	1
Station 80	Station 67	5.900	2007/2008	115	1
Station 82	Station 48	9.500	2007/2008	115	1
Station 48	Station 7	7.500	2007/2008	115	1
Station 121	Station 230	5.700	2007/2008	115	1
Station 80	Station 80	xfrm	2007/2008	345/115	1
Sterling	Off Shore Wind Farm	10.15	2008	138	1
Hurley Ave	Saugerties	11.11	2011	115	1
Pleasant Valley	Knapps Corners	17.7	2011	115	1
Northport	Narwalk Harbor	11	2011	138	3
Saugerties	North Catskill	12.25	2012	115	1
Ramapo	Tallman	3.240	2007	138	1
Tallman	Burns	6.080	2007	138	1

Operations — No unusual operational issues have been identified for the period of 2006–2015.

Ontario

Demand — The actual summer peak demand for 2005 was 26,160 MW, which is 8.3 percent higher than the normal weather forecast of 24,147 MW in the previous report. The actual winter peak for 2005/2006 was 23,766 MW, or 2.4 percent lower than the 24,339 MW normal weather forecast in the previous report.

Ontario has historically experienced its annual peak demand in the winter. However, in recent years the system has been dual-peaking as cooling load has been growing much more quickly than heating. Going forward, this trend will continue and Ontario will be summer peaking.

The summer peak demand is expected to grow at an annual rate of 1.1 percent. The winter peak is expecting an average growth of 0.7 percent over the forecast.

The IESO uses weather scenarios to capture the variability in demand due to weather. Load forecast uncertainty (LFU), a measure of demand fluctuations due to weather variability, is a critical part of demand analysis. In conjunction with the normal weather forecast, LFU is valuable in determining a distribution of potential outcomes under various weather conditions. The IESO resource adequacy

assessments use the normal weather forecast in combination with LFU to consider a full range of peak demands that can occur under various weather conditions with varying probability of occurrence. An extreme weather scenario is developed based on the most extreme weather experienced over 31 years of weather history. This scenario is valuable for studying situations where the system is under duress, especially during peak periods.

Energy — The actual Ontario energy demand for 2005 was 157.0 TWh. This was 0.9 percent higher than last year's forecast for 2005. Despite this, the new forecast calls for lower energy levels throughout the forecast period. The unusually warm summer of 2005 masked a significant loss of load due to reduced economic activity. The high Canadian dollar and high energy costs have adversely impacted a significant portion of Ontario's industrial sector. Energy demand is expected to grow by 0.9 percent per annum over the course of the forecast.

Resources — Since last summer, more than 600 MW of new supply has been added to the Ontario power system, including 515 MW at the Pickering Nuclear Generating Station and 117 MW of gas-fired co-generation. Recent capacity additions have improved Ontario's supply outlook in the short term. The IESO is anticipating a positive capacity margin of approximately 181 MW on the peak week based on forecasted weather-normal demands for the summer of 2006, as compared with a projection of 740 MW for the summer of 2005.

Under median demand growth assumptions, resources that are currently available within Ontario, together with the contracted new generation and imports, are sufficient to meet the NPCC resource adequacy criterion from 2006–2015.

Considerable steps have been taken and are planned to enable retirement of Ontario's coal-fired units (6,500 MW). In executing these changes, flexibility is essential to accommodate the large amounts of new generation required and the impact of each change on the entire system. Careful and continuous coordination and adjustment of plans is taking place to ensure successful implementation of the coal replacement program while maintaining reliability.

Provincial government directives and procurements by the Ontario Power Authority (OPA) will bring 6,300 MW into service over the ten-year period to meet demand and to implement the coal replacement program.
The IESO adequacy assessments include only those projects that are under construction or that have power supply contracts with the Ontario Power Authority. Additional demand measures and supply additions are under development and will be included as future resources once contractual arrangements are in place.

Coal units will be retired once new supply is in service.

The Ontario Power Authority (OPA) has responsibility for long-term supply, integrated power system planning, development of conservation, and demand-related measures and development of retail rate programs. This assignment of responsibilities has been implemented to provide assurance of adequate future electricity supply for Ontario. The OPA's first integrated power system plan (IPSP) is expected to be developed later this year, with Ontario Energy Board approval targeted for 2007. The IPSP will address Ontario's electricity needs for the next 20 years. Generation deliverability to load is not currently an issue in Ontario, and future requirements will be managed as part of the IPSP.

For the period 2006–2015, neither full responsibility purchases nor full responsibility sales are contracted.

Fuel — In anticipation of growing amounts of gas-fired generation in Ontario over the coming years, the IESO has joined with Union Gas, Enbridge, TransCanada Pipelines, and the Ontario Energy Board to

form the Ontario Gas Electric Interface Working Group (OGEIWG). This group will establish communication protocols, cross-functional training, contingency analysis, and gas-electric day coordination in order to manage operational and reliability issues in both energy sectors. The Ontario Energy Board also has proceedings under way to review infrastructure and tariff issues.

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 nonrenewable resources such as coal, uranium, oil, and gas is sufficient such that more explicit analysis is considered only on an ad hoc basis.

Transmission — Transmission capability into the greater Toronto area has been enhanced over the past year with the addition of the second 500/230 kV, 750 MVA auto-transformer at the Parkway TS in the fall of 2005, a 240 Mvar shunt capacitor at the Essa TS, and the planned removal of deratings on the 500/230 kV, 750 MVA autotransformer at the Trafalgar TS.

Imports from New York were limited at times by transmission constraints internal to Ontario in the summer of 2005. These limitations are being addressed by augmenting the five existing 230-kV circuits between Niagara Falls and Hamilton that form the Queenston Flow West interface with a new 230-kV double circuit line between the Allanburg TS and the Middleport TS. This expansion project, together with improved 230-kV circuit ratings in the Burlington area, will remove these internal restrictions. New York imports are expected to be limited by the ties to New York, with a net increase in import capability of about 350 MW. In addition, an existing special protection system at St. Lawrence is planned to be enhanced and be available under peak load conditions to maximize simultaneous import capability from Hydro-Québec and New York. These changes, targeted for the summer of 2006, will increase Ontario's ability to import from New York.

A number of other transmission reinforcements are being developed to permit the connection of new generation to the Ontario system. Most significant of these is the need to increase 500-kV transmission capability from the area around the Bruce nuclear plant to accommodate the return of the two nuclear units and new supply from up to 1,000 MW of wind. The final arrangements have not been decided, but they will need to be in service by 2012 to avoid delaying the restart of the nuclear units.

Interregional transmission transfer capability studies are conducted semiannually. The results are summarized below. The results have not been reviewed or accepted by IESO neighbors. Their limitations could be more restrictive in some cases.

	Winter (MW)	Summer (MW)
Ontario to Manitoba	275	263
Manitoba to Ontario	275	263
Ontario to Minnesota	140	140
Minnesota to Ontario	90	90
Ontario to Michigan	2000	1900
Minnesota to Michigan	1550	1400
Ontario to New York	1900	2100
Minnesota to New York	2000	2250
Ontario to Québec	835	750
Minnesota to Québec	1495	1400

Operations — The phase angle regulators (PARs) were in service on the Michigan-Ontario interconnections, but are being operated by the IESO at neutral tap position because an agreement to operate the PARs to control flow has not been reached. The IESO reports that high loop flows continue to be present through the Ontario system. The PARs were installed by Hydro One in Ontario to mitigate

the problems caused by the loop flows affecting Ontario's most heavily used interfaces. However, this equipment cannot be used as intended until the IESO and the Midwest Independent Transmission System Operator (MISO) complete a corresponding operating agreement, which is currently awaiting negotiations between Hydro One and the International Transmission Company.

The inability to regulate flows combined with lower than expected ratings on the equipment resulted in significant congestion of imports from the Michigan direction in 2005. Until the necessary agreements are in place, the PARs will only be operated off neutral tap to prevent a 5 percent voltage reduction in Ontario or Michigan, to prevent shedding firm load, and for testing. Without agreement to control flow, the congestion experienced in 2005 can be expected to reoccur in 2006.

IESO has been working with government and stakeholders to address some of the problems that surfaced last summer when IESO relied on extensive use of emergency control actions in order to maintain reliability and avoid power interruptions. These measures, which will be implemented in the second quarter of 2006, will include:

- A day-ahead commitment process which is expected to reduce the failure of import transactions in real time and increase commitment certainty for both domestic and out-of-province generators; and
- An emergency load reduction program which will reduce consumption when required for reliability by providing incentives to loads to reduce their energy usage under stressed system conditions.

IESO has achieved significantly better blackstart preparedness after the blackout in August 2003 by procuring additional blackstart capability and requiring actual line energization tests annually in conjunction with existing generator blackstart tests.

Québec

Demand — The 2006–2007 winter peak-demand forecast, under normal weather conditions, is 36,479 MW and is expected to grow at an annual average rate of 0.61 percent, reaching 38,538 MW for the winter period of 2015–2016. This compares with the 2005 RAS *Long-Term Reliability Assessment* projection in which an annual average rate of 0.66 percent was forecast, with a peak of 37,951 MW projected for the winter of 2014–2015. In addition, Hydro-Québec Production has firm export commitments of 455 MW to neighboring networks outside Québec until October 2012. These capacity sales will decrease gradually down to 151 MW in October of 2016.

For the winter of 2005–2006, Québec had 1,235 MW of industrial interruptible load contracts. These contracts are expected to be renewed during the entire study period.

The high load scenario for the period 2005–2006 through 2009–2010 is as follows:

2005–2006	37,288 MW
2006–2007	37,509 MW
2007–2008	38,069 MW
2008–2009	38,699 MW
2009–2010	39,313 MW

The required 0.1 LOLE criterion is met in all years except for the winter of 2005–2006, when it is 0.102. External purchases will be employed if that load level is reached.

Energy — During 2006, the internal energy consumption is expected to total 192 TWh. Between 2006 and 2015, the annual consumption will grow at an average rate of 0.67 percent, reaching 204 TWh in

2015. For the winter of 2005–2006, an actual net energy for load of 183,310 GWh was recorded; an average growth rate of 1.0 percent was projected.

Resources — In the *2005 Québec Area Triennial Review of Resource Adequacy*, Québec demonstrated that the installed reserve margin requirement was about 10 percent over the annual peak load to comply with the NPCC adequacy criterion (Reference https://www.npcc.org/publicFiles/documents/adequacy/Quebec%20Triennial%202005.pdf). For the whole period, the expected installed reserve margin will be over this percentage. Even in the case of a high load scenario, Québec still meets the NPCC resource adequacy criterion (LOLE less than 0.1 day/year).

From January 2006 to January 2016, Québec capacity will increase by 4,500 MW. This increase will come from new and upgraded hydro generation plants and a new gas-fired combined-cycle plant of 547 MW (September, 2006). The overhaul of the nuclear station Gentilly 2 is planned from March 2011 to December 2012.

By 2013, the installed wind power capacity will be more than 3,500 MW. In this assessment for Québec, wind power capacity is not included. Hydro-Québec is in the process of evaluating the capacity value of wind power generation under winter peak weather conditions.

For the period 2006–2015, no full responsibility purchases have been contracted. Hydro-Québec Production has firm export commitments of 455 MW to neighboring networks outside Québec until October of 2012. These capacity sales will decrease gradually to 151 MW in October of 2016.

Fuel — Québec's energy is largely produced (93 percent) by hydro generating stations, located on different river systems geographically distributed, the major ones with multiyear storage capability. For planning and day-to-day operations, Québec can rely on those multi-year reservoirs (water reserves) and on some other nonhydroelectric resources, allowing Québec to cope with low water inflow conditions. Based on the actual water reserves and the other nonhydroelectric resources, generation shortage problems are not expected for the short and medium term.
Regarding the thermal units, each has on-site fuel storage that can be refueled by truck or by barge. The new gas-fired combined-cycle plant has a firm natural gas supply contract for the next five years.

Transmission — During the next five years, about 450 miles of new transmission lines will be added to the Hydro-Québec TransÉnergie grid. The major focus of the new transmission will be the integration of additional generation provided by wind farms and hydroelectric projects with the main grid. Moreover, the Gaspesia subsystem will be reinforced to integrate around 1,500 MW of wind generation.

Presently, the integration of a new HVdc link in the Outaouais subsystem is being studied. This HVdc link is planned to have a capability of 1,250 MW and would be connected to the Ontario grid. A scenario under study is considering a commissioning for the end of 2009.

The major focus of the new transmission will be the integration of additional generation provided by wind farms and hydroelectric projects with the main grid. Moreover, the Gaspesia subsystem will be reinforced to integrate around 1,500 MW of wind generation.

Operations — No unusual operational issues have been identified for the period 2006–2015.

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/).

NPCC-Canada Capacity and Demand

Figure 25: NPCC-Canada Net Energy for Load

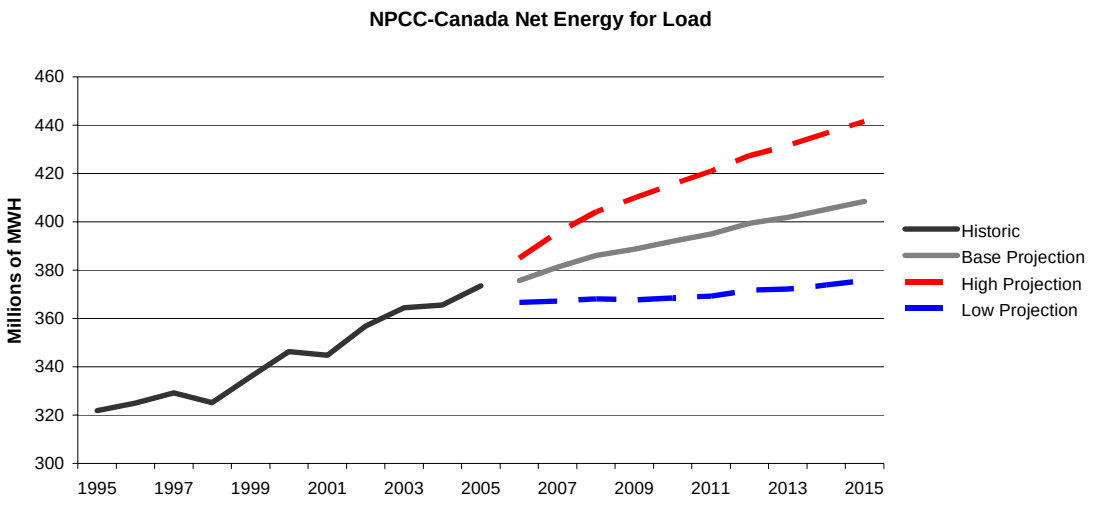


Figure 26: NPCC-Canada Capacity Margins — Winter

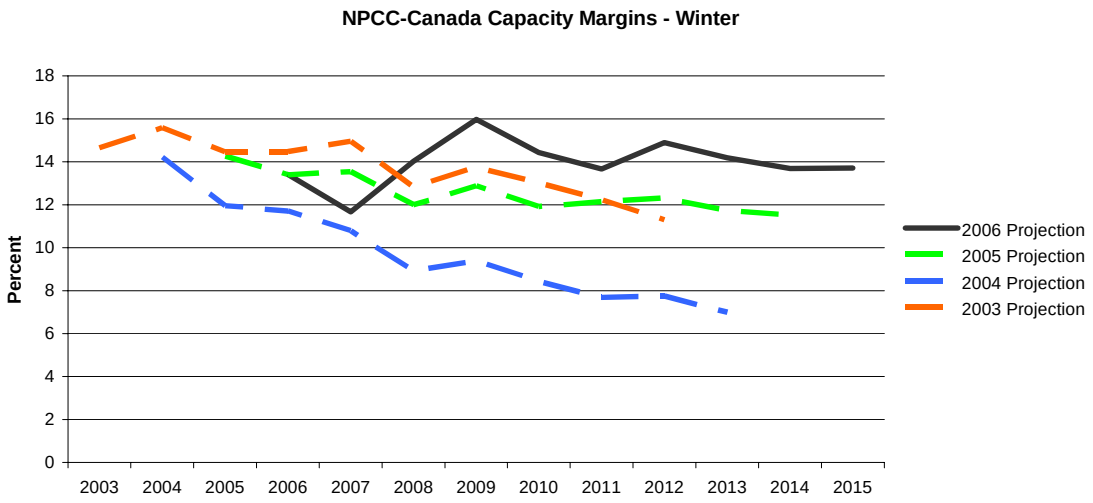
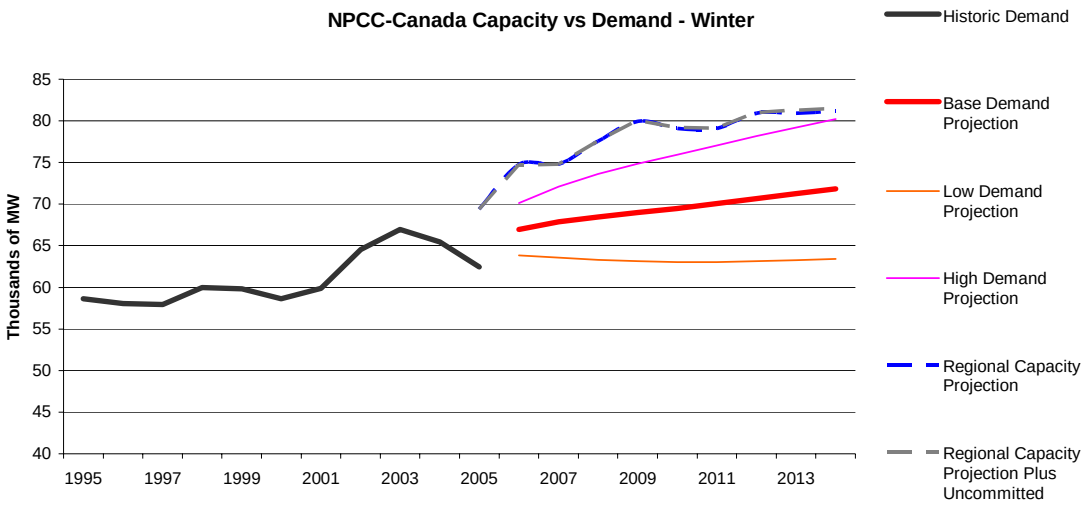


Figure 27: NPCC-Canada Versus Demand — Winter



NPCC-U.S. Capacity and Demand

Figure 28: NPCC-U.S. Net Energy for Load

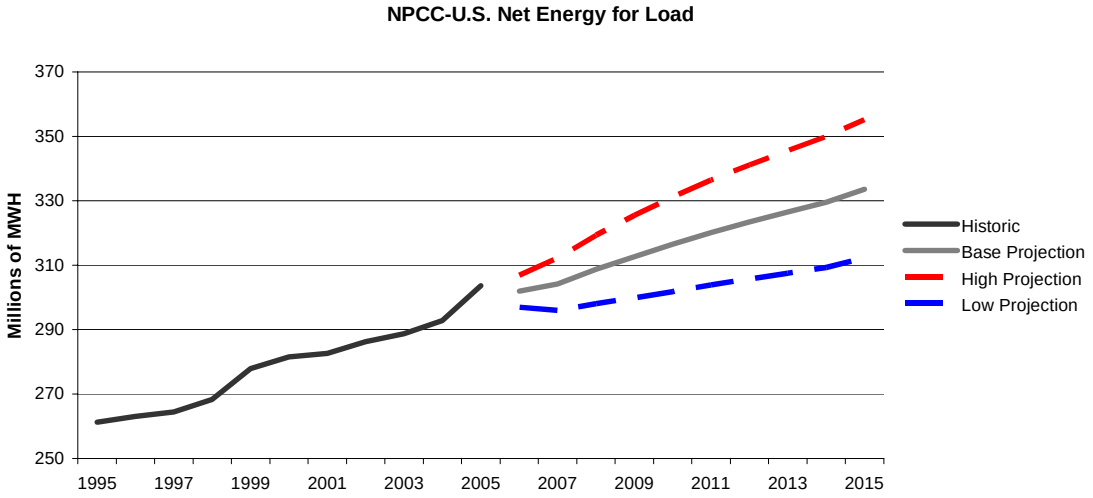


Figure 29: NPCC-U.S. Capacity Margins — Summer

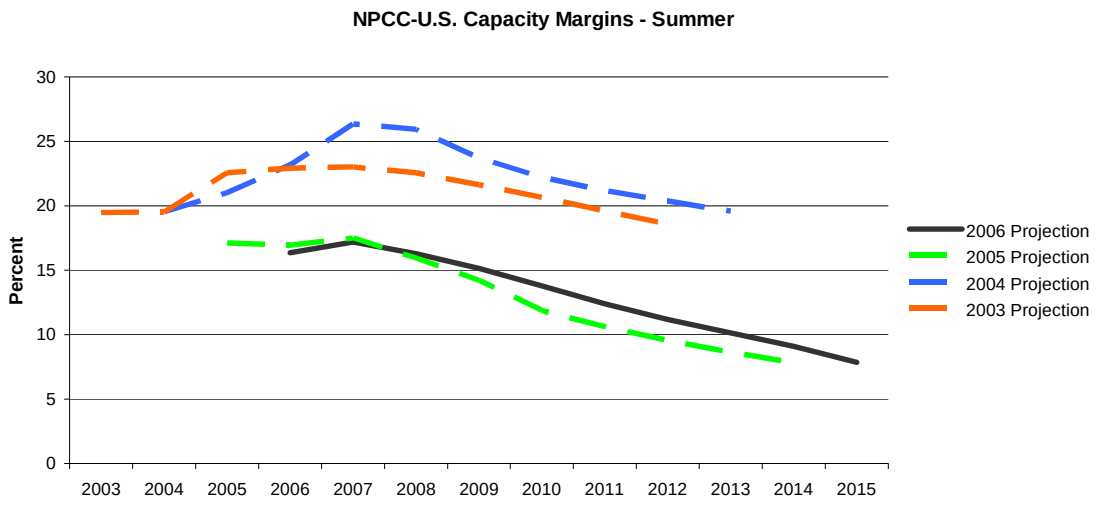


Figure 30: NPCC-U.S. Capacity Versus Demand — Summer

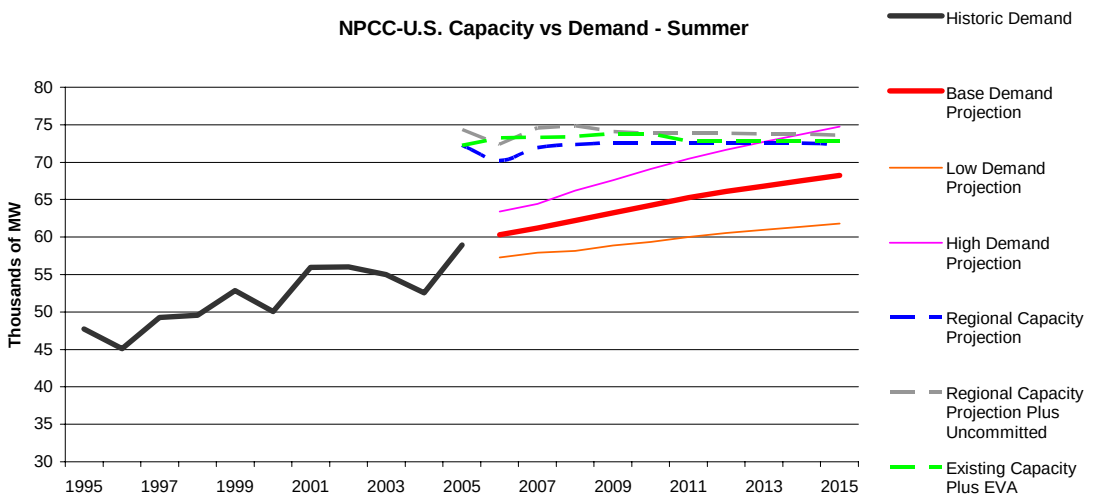


Figure 31: NPCC-Canada Capacity Fuel Mix for 2005 and 2011

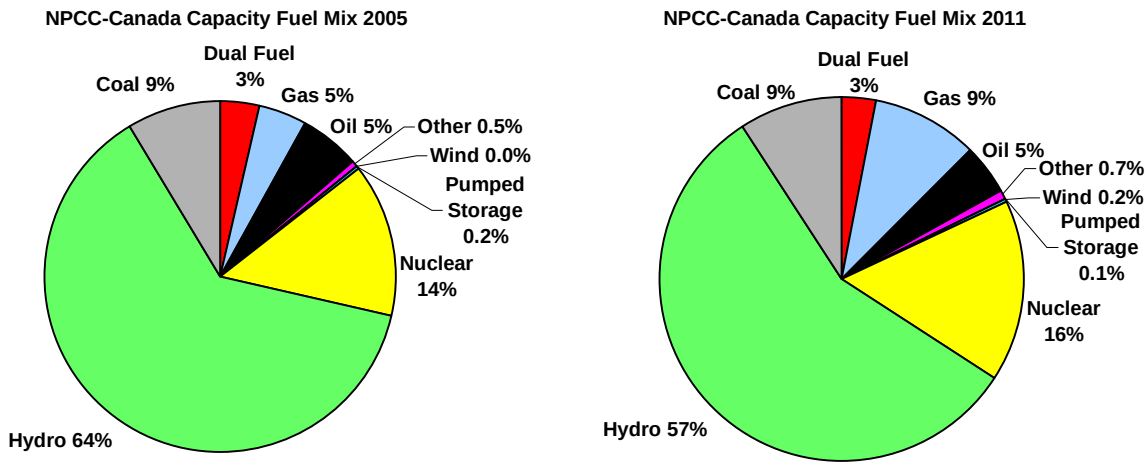
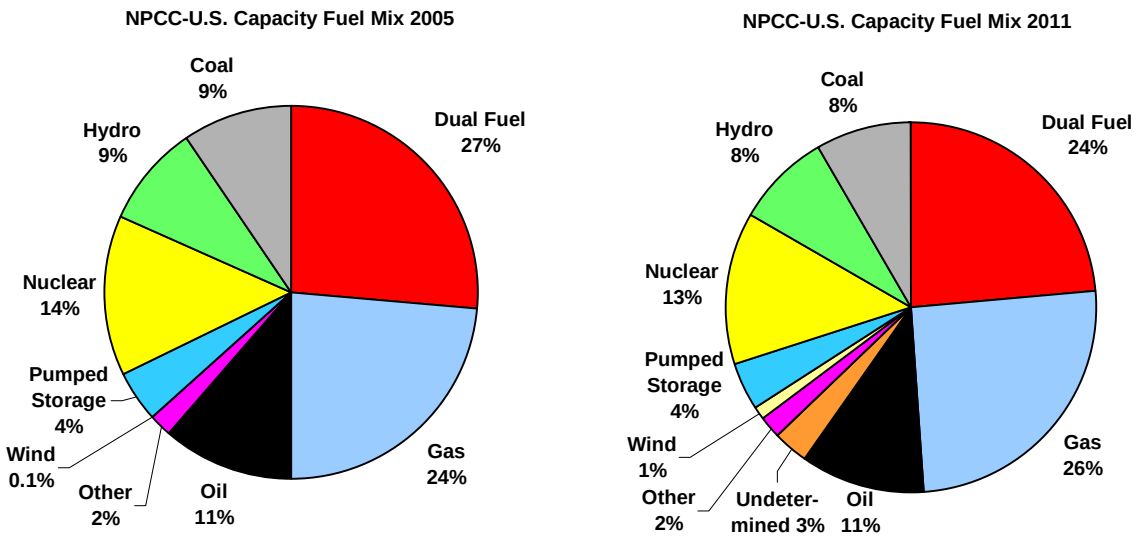


Figure 32: NPCC-U.S. Capacity Fuel Mix for 2005 and 2011



RFC

Demand

Throughout the assessment period, the annual peak in the Reliability*First* Corporation (RFC) region is expected to continue to occur during the summer. Current resource projections developed by RFC members indicate that direct-controlled and interruptible load management programs will provide up to 4,100 MW of expected load reduction at the time of the peak during the years 2006–2015. The coincident total internal demand is expected to be 191,600 MW in 2006 and 220,400 MW in 2015. With curtailment of interruptible loads and demand-side management loads, RFC's coincident net internal demand is projected to be 187,500 MW in 2006 and 216,400 MW in 2015. This is a 1.6 percent average annual load growth in net internal demand over the 2006–2015 period, which is less than the average growth rate of 1.8 percent in last year's projection. This peak demand growth is based on forecast economic factors and average summer weather conditions, and as such, actual peak demands may vary significantly from year to year.

At this time in the transition of ECAR, MAAC, and MAIN to RFC, an analysis of overall demand uncertainty and variability, and the variability in demand due to weather has not been conducted. Planning for such uncertainties is the responsibility of each individual load-serving entity. Higher than average temperature and humidity can be expected to increase the summer peak demand by as much as 11,000 MW.

Energy

RFC does not currently compare or evaluate energy forecasts since few of the RFC resources are energy limited.

Resources

RFC has adopted a regional standard for resource adequacy of LOLE of one occurrence in ten years. This standard can be reviewed at: www.rfirst.org/committees/RFC_Approved_Standards.html. This standard will be implemented by maintaining a reserve margin determined from LOLE analyses. The studies to determine the reserve margins required by regional LSE are scheduled for completion in 2007, with initial implementation in 2008. Until then, the 15 percent reserve margin of the former MAAC region is being used to assess regional resource adequacy.

The net demonstrated capability is projected to be about 241,000 MW by year end of 2006. This includes capacity from members and nonmembers alike. The total announced increase in generating capacity from 2007 through 2015 is about 15,000 MW. This does not include several thousand megawatts of "possible capacity additions" identified by some members. Approximately 3,700 MW of this potential capacity increase from 2007 through 2015 is in the form of combustion turbines and combined-cycle plants projected to operate on natural gas.

The construction status of many near-term capacity projects is not known until nearly the in-service date, and later projects are not yet under construction. This makes for uncertainty regarding the timing and amount of new capacity additions, and consequently, the expected RFC reserve margins. Additionally, a significant amount of existing capacity is not counted toward meeting the reserve requirements as this capacity is considered undeliverable, is not committed to load within the region, or is an energy only resource.

At this time in the transition of ECAR, MAAC, and MAIN to RFC, a recalculation of the 2005 reserve margins for the RFC members is not available for comparison to the reserve margins in this assessment. Based on capacity information provided by RFC members, an analysis is conducted to indicate the amount of additional capacity or power imports that would be needed to meet the required reserve

margin. No purchases or sales after 2006 are included in the analysis. Summer reserve margins in RFC range from a high of 23.0 percent in 2006, declining to 11.1 percent in 2015. These reserve margins are based on forecast net internal demand and potential capacity resources.

The amount of potential capacity resources is sufficient through 2012. Starting in 2013, additional capacity resources are needed to maintain a 15 percent reserve margin. The amount of needed capacity resources ranges from 1,600 MW in 2013 to 8,400 MW in 2015. These reserve margins include over 19,800 MW of projected capacity additions and existing capacity that is currently categorized as undeliverable. If the proposed capacity projects are not completed as scheduled and the transmission system is incapable of fully delivering all existing capacity, a reduction of the entire 19,800 MW of capacity resources would reduce the reserve margin in 2015 to 1.9 percent.

Fuel

RFC does not specifically address fuel supply interruptions on a prospective basis in the long-term assessment. Fuel supply interruptions tend to be local in nature, that is, the failure of the supply network is due to an equipment breakdown or other problem in a specific location. These types of failures in the supply network are difficult to predict, generally short lived, and affect a specific area. Member companies have taken actions in the past to resolve local fuel supply issues. Such actions have included alternate transportation arrangements, fuel switching, and fuel conservation. RFC expects its members will continue to take appropriate action to resolve any short-term fuel supply interruptions into the future, and anticipates that its members will secure adequate fuel supplies throughout this assessment period.

The region is diversified with regard to the fuel supply. About 47 percent of the existing capacity uses coal for its fuel, with 94 percent delivered by rail/truck/barge and 6 percent coming from mine mouth sources. Another 14 percent of the capacity is nuclear fueled. This 61 percent of the capacity is primarily base and intermediate duty generation. Oil and natural gas fuels comprise 7 percent and 28 percent of the capacity, respectively, and 3 percent of the capacity is hydroelectric. The remaining 1 percent of capacity uses a variety of renewable and other energy supplies.

The RFC seasonal peak occurs during the summer, when the oil- and gas-fired capacity will experience the most significant day-to-day usage swings, as these are most often the units operating on the margin during the peak. A review of the gas transmission system indicates that gas transmission contingencies during the summer would not be expected to have a significant effect on generating unit operations across the region, although local problems could exist.

Extreme weather conditions can impact the fuel supply in a number of ways. An extended drought can reduce river levels such that barge transportation of fuel is reduced or curtailed. Extreme summer heat can warp rails, causing train derailments. Flooding can also cause derailments or washed out tracks. Extreme cold can cause coal to freeze together in the rail cars, and heavy snow can slow down train and truck traffic. All of these extreme weather conditions can create short-term problems in fuel supply. However, RFC does not expect weather conditions to materially affect the ability to adequately supply generation across the region during the assessment period.

Transmission

The transmission networks are expected to meet adequacy and operating criteria over a wide range of anticipated system conditions as long as established operating procedures are followed, limitations are observed, and critical facilities are placed in service when required. Local transmission overloads are possible during some generation and transmission contingencies. However, members would use operating procedures to effectively mitigate such overloads.

Current member plans in the next five years project the addition of about 592 miles of extra high-voltage (EHV) transmission lines, (230 kV and above) as well as six new substations that are expected to enhance and strengthen the bulk transmission network. Most of those additions are connections to new generators, or substations serving load centers. Depending upon specific dispatch patterns of new and existing generation, the output of all planned generation may not be fully deliverable due to transmission limitations.

The Neptune Regional Transmission System, LLC merchant transmission interconnection project consists of one HVdc connection from PJM to New York. The connection originates near the Sayreville 230-kV (a.k.a. Raritan River) substation in Sayreville, New Jersey, and will terminate at the Newbridge Road 138-kV substation on Long Island, New York. Capability will be 790 MW and the developer has requested firm transmission withdrawal rights in the amount of 685 MW and nonfirm transmission withdrawal rights in the amount of 105 MW at the HVdc terminal in PJM. Neptune is scheduled for commercial operation in July 2007.

PJM is also evaluating several additional proposals for EHV transmission to increase overall west-to-east transfer capability by at least 5,000 MW. In-service dates are expected to be within five to ten years. More details will be reported in future reliability assessments. More information is available at: www.pjm.com.

RFC actively participates in existing interregional transmission assessment efforts. Transfer capability results are included in each of the interregional reports. New interregional agreements are being negotiated between RFC and its neighboring regions.

Legacy regional activities that were initiated as a result of the August 14, 2003 blackout have continued and may be applied to all RFC members in the near future. One of these activities is a peer review process of transmission assessments to verify that owners and operators have conducted sufficient planning analyses and to complement regional assessment efforts. Since the blackout, five peer reviews of former ECAR member transmission assessments have been conducted. All assessments included both thermal and voltage analyses for a base case and several stressed case conditions with single, double, and if warranted, extreme contingencies. The results of these assessments are communicated to reliability coordinators and transmission operators. A review of all of these activities is currently being performed to determine if they will continue for all RFC members.

Operations

MISO, PJM Interconnection, and TVA are performing the reliability coordinator functions for all of the balancing authorities in the region.

Eight NERC readiness audits are being conducted in RFC in 2006. Numerous operational improvements have been implemented as a result of the recommendations from the readiness audits. The most widespread of these operational improvements dealt with improved emergency and restoration training, improved security analysis procedures and programs, and improved communications between and among reliability coordinators, balancing authorities, and transmission operators.

To mitigate congestion and other reliability concerns at the interface between PJM and MISO, a joint MISO-PJM operating agreement is in place. The agreement identifies the transmission rights and obligations of MISO in the PJM footprint and the transmission rights and obligations of PJM in the MISO footprint. Further, each RTO has the ability to request that generation be operated in the other RTO to preserve transmission rights and to relieve congestion in its footprint.

RFC is not aware of any specific operating issues that need to be addressed in this assessment.

Assessment Process

Transition to a single set of assessment processes is still in progress for all of the previous heritage regional activities. Consequently, this long-term assessment reflects an aggregation of three separate assessment activities, conducted by using the assessment processes of ECAR, MAAC, and MAIN.

Within RFC, each individual company along with its 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.

For the RFC members that were ECAR members, ECAR's assessment procedures were applied to all generation and transmission facilities within the former ECAR portion of the RFC footprint that might significantly impact bulk power system reliability. These assessments consider ECAR as a single integrated system. Generation resource assessments of the ECAR systems on a region-wide basis have been performed annually for a planning horizon of up to ten years, and semiannual assessments have been made for the upcoming summer and winter peak-demand seasons. Transmission assessments have been performed regularly for selected future years out to the planning horizon and semiannually for the summer and winter peak-demand seasons. If transmission deficiencies are discovered during this process, the member system with the deficiency will determine the actions to be taken.

For the RFC members that were MAAC members, PJM's assessment practices continue to apply. PJM's assessments cover the entire expanded PJM RTO footprint, which now includes the transmission systems in all or part of Pennsylvania, New Jersey, Maryland, Ohio, Kentucky, Delaware, Virginia, West Virginia, Illinois, North Carolina, and the District of Columbia. In addition to the former MAAC members, this PJM footprint also includes several former ECAR and MAIN members. The PJM RTO is operated and planned 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 planning process has been expanded to evaluate reliability, economic, and operational performance projects. The reliability projects are designed to meet reliability criteria, while the economic projects are justified based on a cost-benefit analysis, which considers congestion costs and takes into account various financial hedging instruments. PJM performs these economic analyses for the PJM members' information only to point to areas where development of transmission or generation may be financially beneficial. Operational performance projects are intended to address events that are observed by the PJM operators, but were not predicted in the planning studies.

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. A reserve requirement is presently set for a planning period two years into the future so that the market can provide sufficient capacity or for the load-serving entities to construct generation. A future reserve construct, which values the quantity, quality, and location of generation, is presently going through the stakeholder process.

The MISO market rules also include the use of a locational marginal pricing mechanism to make congestion transparent. The MISO energy market tariff requires LSEs to comply with their applicable RRO or state resource adequacy standards. Load and capability information is reported to MISO annually. To monitor compliance a planned reserve sharing group (PRSG) for the MISO LSE is currently under development. The PRSG will be designed to meet planned resource requirements of RFC.

Finally, for those RFC members that were MAIN members, the former MAIN transmission assessments included a 2009 dynamic stability-based study for a 2014 screening, and studies completed by the former MAIN Future System Study Group.

*RFC membership currently consists of 46 regular members and 19 associate members operating within 12 NERC aalancing 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).*

RFC Capacity and Demand

Figure 33: RFC Net Energy for Load

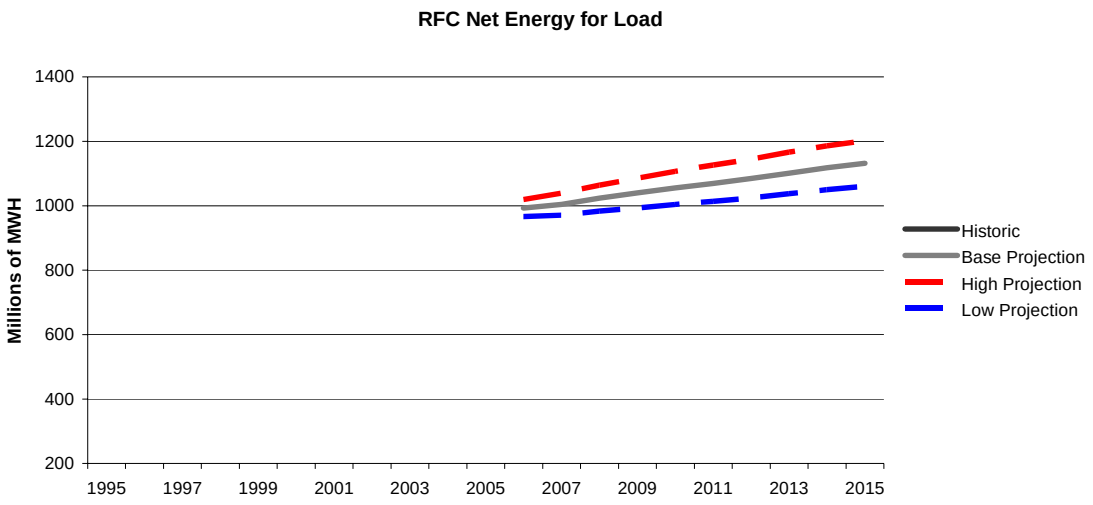


Figure 34: RFC Capacity Margins — Summer

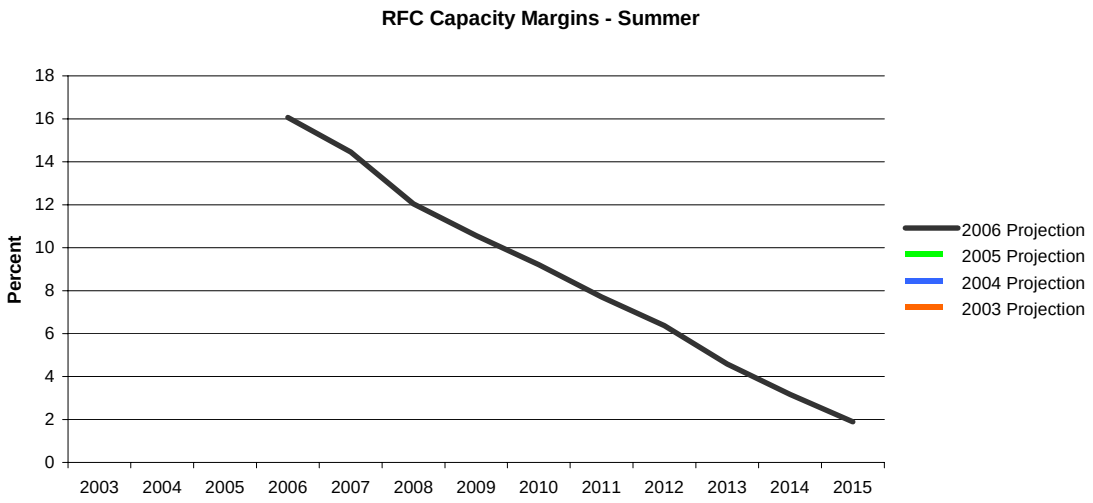


Figure 35: RFC Capacity Versus Demand — Summer

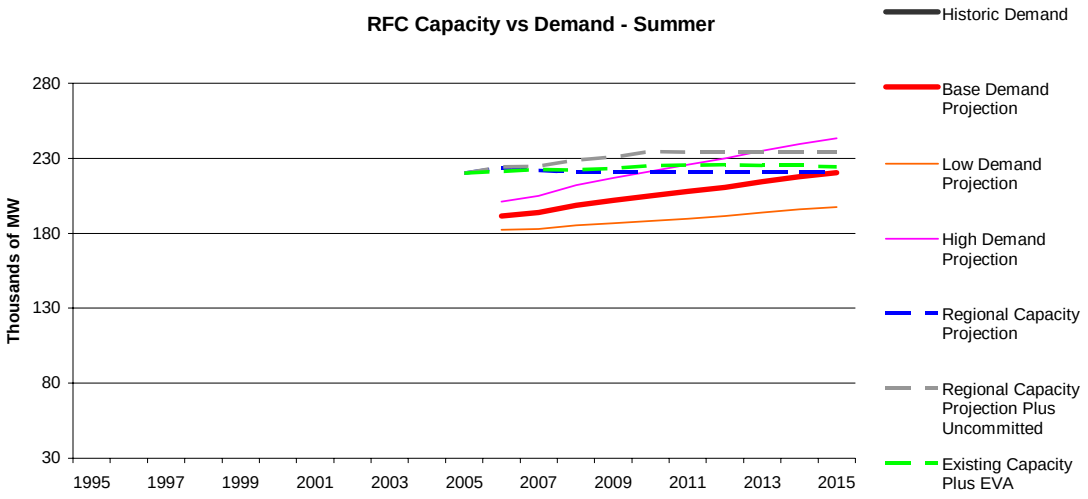
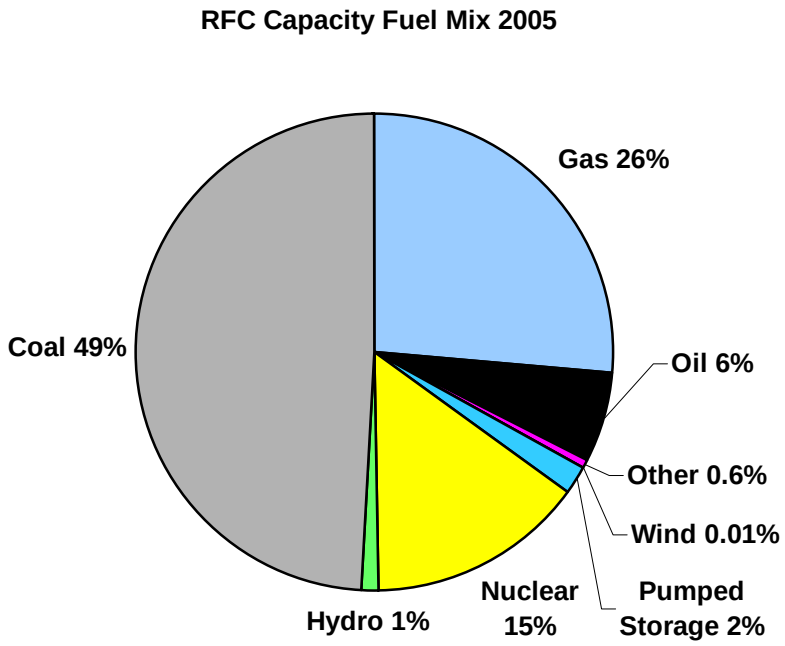
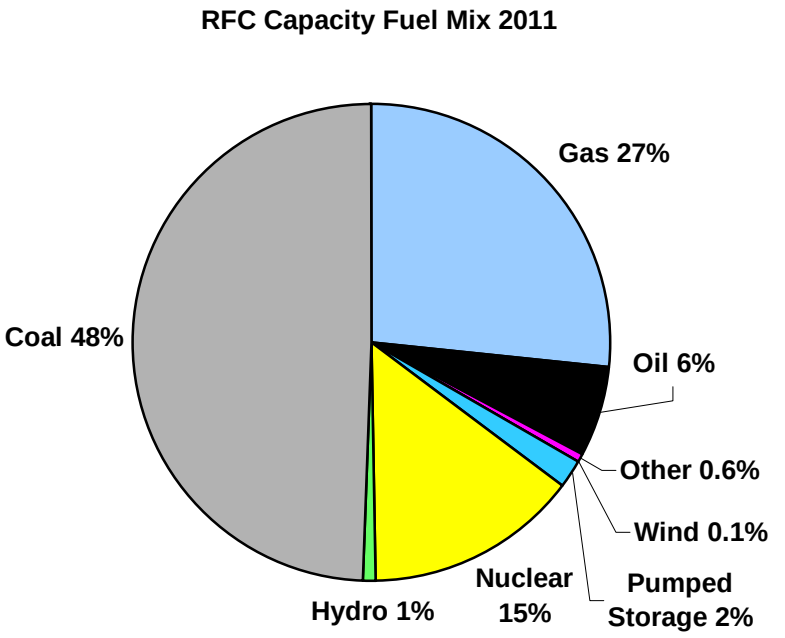


Figure 36: RFC Capacity Fuel Mix for 2005 and 2011





SERC

SERC anticipates consistent load growth in demand and energy over the next ten years.

The SERC region has extensive transmission interconnections between its subregions and its neighboring regions (FRCC, MRO, RFC, and SPP). These interconnections allow the exchange of large amounts of firm and nonfirm power and allow systems to assist one another in the event of an emergency.

Transmission capacity is expected to be adequate to supply firm customer demand and firm transmission reservations. Planned transmission additions include 1,624 miles of 230-kV lines, 270 miles of 345-kV lines, and 345 miles of 500-kV lines. SERC members invested over $1.25 billion in new transmission lines and system upgrades in 2005, and they are planning transmission capital expenditures of more than $6.75 billion over the next five years.

SERC is in a period of significant transition:

- 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, City of Columbia, Missouri, Electric Energy, Inc., Illinois Municipal Electric Agency, and Southern Illinois Power Cooperative. All but Electric Energy, Inc. are also members of the Midwest ISO.
- Also effective January 1, 2006, two new SERC members, East Kentucky Power Coop. (EKPC) and Big Rivers Electric Coop. (BREC), joined the TVA subregion.
- Development of an interregional studies agreement among the regions of the Eastern Interconnection is nearing completion and SERC has recently integrated a new framework for studies into the region's organization. Future intraregional and certain interregional study efforts will be coordinated by these SERC groups to ensure continued reliability during these times of change.
- Major changes in the electric utility industry were mandated by the Energy Policy Act of 2005. SERC is undergoing organizational and governance changes to align with the legislation.

Throughout the transition, SERC's focus remains on ensuring reliability.

Demand

The 2006 summer total internal demand forecast is 188,763 MW and the forecast for 2015 is 226,921 MW. The average annual growth rate over the next ten years is 2.1 percent. This is the same as last year's forecast growth rate. The historical growth rate over the last five years averaged 1.9 percent.

Due to the geographic size of the region, all reported demands are noncoincident. These forecasts are based on average historical weather conditions.

The SERC region has significant demand response programs. These programs allow demand to be reduced or curtailed when needed to maintain reliability. The amount of interruptible demand and load management is expected to decline slightly over the forecast period from 4,980 MW in 2006 to 4,838 MW in 2015. These amounts are comparable to last year's projections. In addition to the reported interruptible demand and load management, other significant demand-side management programs are also available to maintain reliability in the region.

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 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 still 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.

Energy

The actual annual electric energy usage in the SERC region during 2005 was 962,054 GWh. The forecast annual electric energy usage in the SERC region during 2006 is 973,215 GWh. This is an increase of 1.2 percent. The forecast annual growth rate in energy usage for the region over the next ten years is 1.7 percent, which is the same as last year's forecast growth rate. The historical SERC growth rate for the last ten years has been 2.1 percent.

Resources

SERC believes that capacity resources will be sufficient to provide adequate and reliable service for forecast demands throughout the long-term assessment period. The 2006 forecast for capacity margins show that the margin is projected to remain at or above 14 percent throughout the ten-year period. Capacity margins from last year's forecast started above 12 percent, fell below 10 percent in the near term, and remained between 6–8 percent in the longer term. This year's forecast is higher than last year's due to changes in data reporting philosophies that include more comprehensive longer-term plans, and recent acquisitions of previously uncommitted merchant generating facilities that are now committed to serving load in the region. Uncommitted capacity in the SERC region is not included in this capacity margin assessment. If a load-serving entity has a contractual arrangement with a merchant plant and therefore reported through the EIA-411 reporting process, then this capacity is included in this capacity margin assessment. Because significant uncommitted capacity exists in the region, additional generation above that which is reported in the capacity margin trend will continue to be in place. Capacity margin calculations assume the use of load management and interruptible contracts at the time of the annual peak.

Collectively, SERC members are projected to be net sellers of firm power across regional boundaries throughout the ten-year period. Firm purchases from SPP reach almost 700 MW, but are offset by sales to SPP of about 250 MW. Sales to FRCC reach 1,550 MW. Purchases from RFC reach approximately 750 MW, of which over 150 MW are to transport remote generation. Only firm transactions are 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 regarding maintaining adequate resources. SERC members use various methodologies to ensure adequate resources are available and deliverable to the load.

Deliverability is an important consideration in the analyses to ensure adequate resources are available at the time of peak demand. 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 guidelines to meet projected customer demands and provide contracted transmission services. Therefore, SERC anticipates no constraints that would reduce the availability of committed capacity resources. In addition, a significant amount of the uncommitted merchant capacity within the region has been participating in the short-term markets.

The projected 2006 capacity mix reported for SERC is approximately 38 percent coal, 16 percent nuclear, 9 percent hydro/pumped storage, 28 percent gas and/or oil, and 9 percent of purchases and miscellaneous other capacity. This capacity mix includes only committed generation. The mix has not changed significantly from last year. Steam technology (includes coal and nuclear) accounts for approximately 62 percent of the net operable capacity in 2007. This is down slightly from the 65 percent reported last year. Generation with coal and nuclear fuels continues to dominate the region's fuel mix, accounting for roughly 54 percent of net operable capacity in 2007. Units fueled by gas or with dual gas/oil capabilities account for 26 percent.

The majority of planned capacity additions are gas/oil fueled, combustion turbine or combined-cycle units. However, the ten-year planning horizon has plans for coal-fired and nuclear plant additions.

Some examples are:

- TVA subregion: Browns Ferry (nuclear) unit 1 — 1,250 MW in 2007
- VACAR subregion: Cross (coal) unit 3 — 650 MW in 2007; Cross (coal) unit 4 — 650 MW in 2009; 2,320 MW merchant nuclear plant for interconnection in 2015
- Gateway subregion: Prairie State (merchant coal) plant — 1,650 MW in 2008
- Southern subregion: 1,200 MW merchant coal plant for interconnection in 2010

Of the approximately 37,000 MW of net planned capacity additions reported for the 2006–2015 time period, 5 percent are combined-cycle, 21 percent are combustion turbine, 11 percent are steam, and 40 percent are categorized as "Other/Unknown." The "Other/Unknown" category includes projected additions that do not have finalized implementation plans. The largest change from last year is a net increase in the steam category from 0 percent to 11 percent. It appears that members are increasingly planning for future coal or nuclear base load generation instead of relying on natural gas or purchases.

Generation Development in SERC

Significant merchant generation development has occurred in SERC since 1998, especially in the Southern and Entergy subregions. Most of this merchant generation was intended for sale in the wholesale markets. However, 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 SERC reported capacity margins.

To understand the extent of generation development in the region, it is instructive to examine how much generation is connected or has requested connection to the transmission system. A summary of aggregate generation interconnection requests is shown in Table 2 below. This table includes both utility and merchant generating plants. Requests reported as "signed/filed" are assumed to have a somewhat higher probability of being built than those listed as "requested only."

Table 2: Current Status of Generation Plant Development in SERC

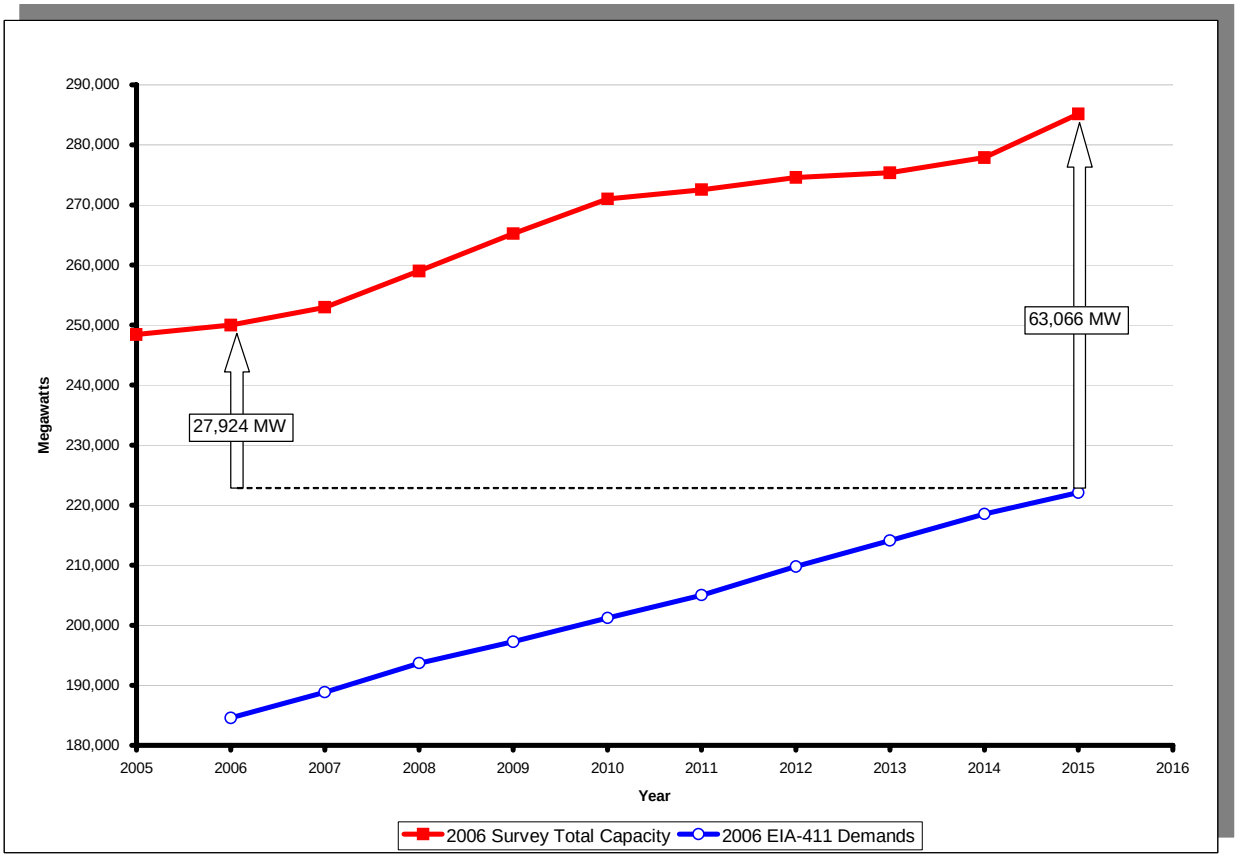
Current Status of Generation Plant Development	In-Service Year of Added Generation (MW)										
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**Total**
1) Interconnection Service Requested, Only	45	1437	4687	4207	1759	114	1137	784	1899	7148	**23217**
> Designated as Network Resource or has obtained Firm PTP Transmission service	45	713	736	2141	1684	74	1022	744	1824	4147	**13130**
> Uncommitted	0	724	3951	2066	75	40	115	40	75	3001	**10087**
2) Interconnection Agreement Signed/Filed	1579	1615	1435	1972	4157	1735	895	0	660	85	**14133**
> Designated as Network Resource or has obtained Firm PTP Transmission service	199	839	885	733	2182	985	895	0	660	85	**7463**
> Uncommitted	1380	776	550	1239	1975	750	0	0	0	0	**6670**
3) Unit Retirements	7	90	88	0	108	298	0	0	0	0	**591**
Net Projected Additions	**1617**	**2962**	**6034**	**6179**	**5808**	**1551**	**2032**	**784**	**2559**	**7233**	**36759**

*Source — SERC Reliability Review Subcommittee 2006 report to the SERC Engineering Committee

The survey indicates that an additional 1,617 MW of generation plant capacity is expected in the SERC region for the 2006 summer, the vast majority of which have signed or filed interconnection agreements by the time of the survey. In the near-term planning horizon, significant speculation exists about the amount of generation that will be added (approximately 6,000 MW for 2008 and 2009 of which over 4,000 MW fall in category 1), but the amount to actually be constructed will likely change before the next annual survey. The reported generation development decreases sharply beyond 2010 as plans for the longer term have not been finalized. The majority of generation development was reported for the first six years and totals 24,100 MW. This compares favorably to the 21,000 MW reported to be operable in the first six years of last year's survey. The amount of the reported planned capacity that will actually be built is highly dependent on factors such as market prices, fuel availability, the ability to arrange suitable interconnection and transmission access agreements, the number of other generation plants that are being constructed, the ability to permit and complete necessary transmission line additions in a reasonable amount of time, the ability of the company to obtain financial backing, and other typical business factors.

As of December 31, 2005, SERC's generation development survey indicated that the total generation connected to the transmission systems in SERC was 248,390 MW. An additional 1,617 MW of generation was planned to be connected to the transmission systems by July 1, 2006, bringing the total to just over 250,000 MW. These values differ slightly from the EIA-411 data due to inoperable capacity and mothballed units. The current total generation connected to the SERC systems exceeds projections for SERC regional load in the year 2015 by over 27,000 MW. If all of the proposed capacity described in Table 2 above is built, installed generation could exceed forecast peak demand by more than 63,000 MW in 2015. This is significantly more than the generation capability needed for reliability/adequacy in the region.

Figure 37: Proposed Generation Development in SERC



*Source — SERC Reliability Review Subcommittee 2006 Generation Development Survey

Fuel

According to assessments completed by SERC members, adequate fuel supplies are expected. 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. Dual-fuel units are tested to ensure their availability, and that backup 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 for the near-term planning horizon is adequate, even considering possible impacts due to weather extremes. Mild winter temperatures experienced in 2005/2006 should result in a stronger gas storage position, which would reduce demand for storage injections. Additionally, new international liquefied natural gas supplies are expected to become available to the United States market during the 2006–2008 time frame.

Active hurricane seasons could periodically curtail Gulf of Mexico fuel production and delivery. Although fuel deliverability problems are possible for limited periods of time due to hurricanes or other 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.

Fuel supply will always be a critical part of the power supply chain, regardless of fuel choice. SERC utilities have been able to maintain fuel diversity in their portfolios, enhancing reliability. Looking forward, SERC is following these issues to ensure reliability is maintained into the longer-term planning horizon:

- Protecting the nation's natural gas production and transportation facilities in the Gulf Coast areas
- Monitoring the development of LNG facilities in both the U.S. and in natural gas producing countries
- Monitoring the next wave of new generation additions over the next 15 years
- Ensuring that the coal delivery infrastructure keeps pace with the forecasted increase in construction of coal generation facilities
- Ensuring that fuel inventories continue to be managed appropriately to mitigate the effects of natural disasters and others causes of disruptions to fuel supplies

Transmission

The existing bulk transmission system within SERC is comprised of 17,067 miles of 161-kV, 20,028 miles of 230-kV, 2,651 miles of 345-kV, and 8,500 miles of 500-kV transmission lines. SERC member systems continue to plan for a reliable bulk power system and plan to add 387 miles of 161-kV, 1,624 miles of 230-kV, 270 miles of 345-kV, and 345 miles of 500-kV transmission lines in the 2006–2015 time period. SERC members invested over $1.25 billion in new transmission lines and system upgrades in 2005, and are planning transmission capital expenditures of more than $6.75 billion over the next five years. To allow the uncommitted generation to become committed generation, some additional transmission investment could be required.

SERC member transmission systems are directly interconnected with the transmission systems in FRCC, MRO, RFC, and SPP. Transmission studies are coordinated through joint interregional reliability study groups. The results of individual system, regional, and interregional studies are used to demonstrate that the SERC transmission systems meet NERC and SERC reliability standards. The transmission systems in SERC are expected to have adequate delivery capacity to support forecast demand and energy requirements and firm transmission service commitments during normal system conditions and NERC Reliability Standard TPL-002 type contingency conditions.

Operations

Coordinated interregional transmission reliability and transfer capability studies for the shorter-term planning horizon were conducted among all the SERC subregions and with the neighboring regions. In addition, coordinated intraregional transmission reliability and transfer capability studies for the longer-term planning horizon were conducted within SERC. These studies indicate that the bulk power systems within SERC and between adjoining regions can be expected to provide adequate and reliable service over a range of system operating conditions.

No major generating unit outages or transmission facility outages which would impact system reliability are planned for peak periods. Environmental restrictions are not anticipated to significantly impact operations.

Assessment Process

Although SERC members plan for facility (transmission and generation) additions on an individual basis, SERC performs many assessment functions at the regional 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 power 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 through 006. (http://www.serc1.org/Pages/ComplianceContentPage.aspx?ID=25).

Entergy

Demand — The 2006 summer net internal demand forecast for the Entergy subregion was 27,114 MW and the forecast for 2015 is 32,151 MW. The average annual growth rate over the next ten years is 1.9 percent. This is higher than last year's forecast growth rate of 1.4 percent. The historical growth rate has averaged 1.8 percent.

Energy — The 2006 annual electric energy usage forecast for the Entergy subregion was 145,013 GWh and the forecast for 2015 is 167,243 GWh. The forecast growth rate in energy usage is 1.6 percent. The historical growth rate for the last ten years is 1.2 percent.

Resources — Projected capacity margin was 21.1 percent for the 2006 summer, and declines to 5.8 percent in 2015. Capacity, in addition to that currently planned, will be needed to maintain reliability. Large amounts of uncommitted generation in the subregion could provide the needed capacity and time is adequate to build new capacity if necessary. For example, in the past year the Perryville and Attala plants were added as network resources for the Entergy operating companies with plant capacities of 718 MW and 463 MW, respectively.

Transmission — Planned transmission additions include 284 miles of 230-kV lines, 105 miles of 345-kV lines, and 30 miles of 500-kV lines.

Operations — Entergy continues to monitor load growth in the cities surrounding the areas affected by hurricanes Katrina and Rita. No reliability concerns are anticipated as a result of the load redistribution. Several substations continue to operate in a functionally and capacity limited state in the impacted zone. In addition, four substations and four transmission lines remain out of service within the same area. Entergy assessments indicate that these out-of-service facilities will not impact regional or local reliability for the coming season. These system elements will be restored as local system requirements dictate. All transmission substations and lines damaged by hurricane Rita in east Texas and southwest Louisiana have been restored.

The domestic natural gas and oil industries are still in a recovery in the aftermath of hurricanes Katrina and Rita. Most major production, processing, and transportation facilities are returning to service, but may still operate at less-than-normal capability in the near term due to limited production facilities in the Gulf of Mexico. Future weather extremes such as tropical disturbances may again affect fuel supply infrastructure or cause fuel delivery problems. However, Entergy will take steps such as managing fuel inventories to mitigate the impact of those types of events.

As a result of the recent hurricane restoration efforts, Entergy identified key success factors to minimize widespread and prolonged power outages in future storms. These include detailed advance planning for "worst case" scenarios, practice-through drills and other means, constantly improving infrastructure, and organization experience and culture. Entergy has determined that a clear command structure, assignment of decision-making at the appropriate level, and an ability to take action in a timely manner play a critical role minimizing power outage duration. High-level support and confidence in the process along with mutual assistance programs are key factors in restoration success.

Gateway

Demand — The 2006 summer net internal demand forecast for the Gateway subregion was 17,611 MW and the forecast for 2015 is 19,606 MW. The average annual growth rate over the next ten years is 1.2 percent. The historical growth rate has averaged 1.3 percent.

Energy — The 2006 annual electric energy usage forecast for the Gateway subregion was 80,220 GWh and the forecast for 2015 is 88,818 GWh. The forecast growth rate in energy usage is 1.1 percent. Energy consumption for 2006 was forecast to be 1.5 percent more than the 2005 actual consumption of 79,028.

Resources — Projected capacity margin was 31.3 percent for the 2006 summer, and remains above 31 percent over the remainder of the planning period.

Transmission — Planned transmission additions include 111 miles of 345-kV lines.

Planned reinforcements in the Jefferson City, Missouri, area are scheduled for completion in 2008 which would increase transfer capability from SERC (Gateway) to SPP.

Operations — The startup of the Midwest ISO energy market on April 1, 2005 created a marked change in dispatch across the Midwest ISO footprint. The Midwest ISO security constrained economic dispatch allows the market to prevent some TLRs prior to escalation of flows. The seams agreements that have recently been initiated with PJM and SPP should further reduce the need to call for TLR because of increased coordination. This and the new auction in the fall of 2006 to supply Illinois retail electric load customers in 2007 are new items for Gateway members and the Midwest ISO to manage.

Southern

Demand — The 2006 summer net internal demand forecast for the Southern subregion was 47,718 MW and the forecast for 2015 is 59,614 MW. The average annual growth rate over the next ten years is 2.5 percent. This is the same as last year's forecast growth rate. The historical growth rate has averaged 2.4 percent.

Energy — The 2006 annual electric energy usage forecast for the Southern subregion was 243,713 GWh and the forecast for 2015 is 299,072 GWh. The forecast growth rate in energy usage is 2.3 percent. The historical growth rate for the last ten years is 2.8 percent.

Resources — Projected capacity margin was 14.7 percent for the 2006 summer, and ranges from 11.4 percent to 14.6 percent over the remainder of the planning period.

Transmission — Planned transmission additions include 693 miles of 230-kV lines and 170 miles of 500-kV lines.

Operations — Southern subregion companies are currently assessing and making adjustments to hurricane restoration manuals from lessons learned during the 2005 hurricane season, particularly regarding the Katrina restoration.

Transmission system stability studies, which have been posted on OASIS, have found four potential stability challenged areas within the Southern subregion. Two of these areas were found during interconnection studies for which the generators requesting interconnection ultimately were not built. Therefore, stability is not currently an issue in these two areas for the amount of generation located in the area now, and for the amount proposed in the foreseeable future. A third area has enough generation still being considered for interconnection that, along with the generation already in service, could create a potential stability concern that must be carefully studied. It may become an operating issue in the future. The fourth area, the southwest quadrant, has substantial generation on the ground which requires that the area must be carefully monitored for stability, especially at lighter system load levels. Management of this stability challenged area is accomplished in real-time operations by monitoring a stability proxy flowgate. System operators monitor flows on the transmission lines which form the boundary of the quadrant. A table of limits for the proxy flowgate, considering specific lines out of service and/or units with PSS out of service, is used to cover all scenarios. Southern Company has also recently implemented online stability tools for system operations.

TVA

Demand — The 2006 summer net internal demand forecast for the TVA subregion was 32,677 MW and the forecast for 2015 is 39,888 MW. The average annual growth rate over the next ten years is 2.2 percent. This is slightly lower than last year's forecast growth rate of 2.3 percent. The historical growth rate has averaged 1.7 percent (excluding new members).

Energy — The 2006 annual electric energy usage forecast for the TVA subregion was 193,392 GWh and the forecast for 2015 is 216,410 GWh. The forecast growth rate in energy usage is 1.3 percent. The historical growth rate for the last ten years is 2.9 percent, which is higher than forecast due to the inclusion of two new members into the subregion in the past year.

Resources — Projected capacity margin was 11.4 percent for the 2006 summer, and ranges from 10.8 percent–12.5 percent over the remainder of the planning period.

Transmission — Planned transmission additions include 54 miles of 345-kV lines and 40 miles of 500-kV lines.

During periods of significant north-south transfers, certain facilities in the subregion experience high loading. Transmission system additions are scheduled for completion by the summer of 2007 that will greatly reduce the loading on the limiting facilities.

Operations — The TVA power system has experienced large and volatile flows in recent years and these flows may continue to occur. 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. Operating guides have been developed to address these constraints.

VACAR

Demand — The 2006 summer net internal demand forecast for the VACAR subregion was 59,447 MW and the forecast for 2015 is 70,824 MW. The average annual growth rate over the next ten years is 2.0 percent. This is the same as last year's forecast growth rate. The historical growth rate has averaged 2.5 percent.

Energy — The 2006 annual electric energy usage forecast for the VACAR subregion was 310,877 GWh and the forecast for 2015 is 362,667 GWh. The forecast growth rate in energy usage is 1.7 percent. The historical growth rate for the last ten years is 1.9 percent.

Resources — Projected capacity margin was 13.1 percent for the 2006 summer, and ranges from 11.9 percent–13.0 percent over the remainder of the planning period.

Transmission — Planned transmission additions include 647 miles of 230-kV lines and 105 miles of 500-kV lines.

Completion of American Electric Power's (AEP) Wyoming to Jacksons Ferry 765-kV line during the summer of 2006 which will relieve congestion between RFC and VACAR.

Operations — Heavy loading internal to the VACAR subregion could be experienced on several facilities. Studies have shown that generation internal to VACAR can be redispatched to relieve the loading on these internal lines, if necessary.

Also, several improvements to VACAR facilities have been completed or are planned. Transmission improvements intended to reinforce delivery of power are expected to be completed in the fall of 2006. Projects have been completed to provide stronger networking of the 115-kV system in Dominion Virginia Power's northwest area.

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).

SERC Capacity and Demand

Figure 38: SERC Net Energy for Load

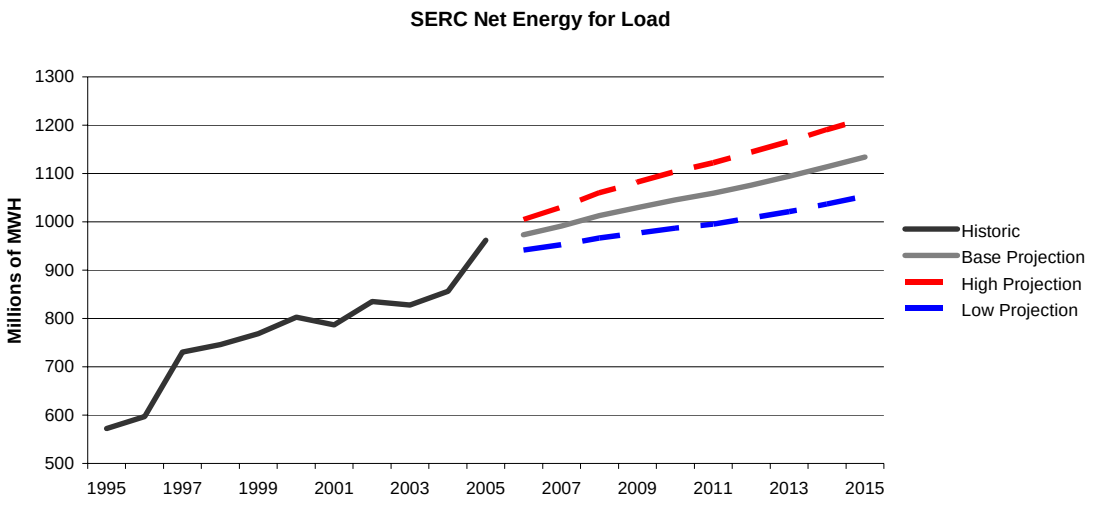


Figure 39: SERC Capacity Margins — Summer

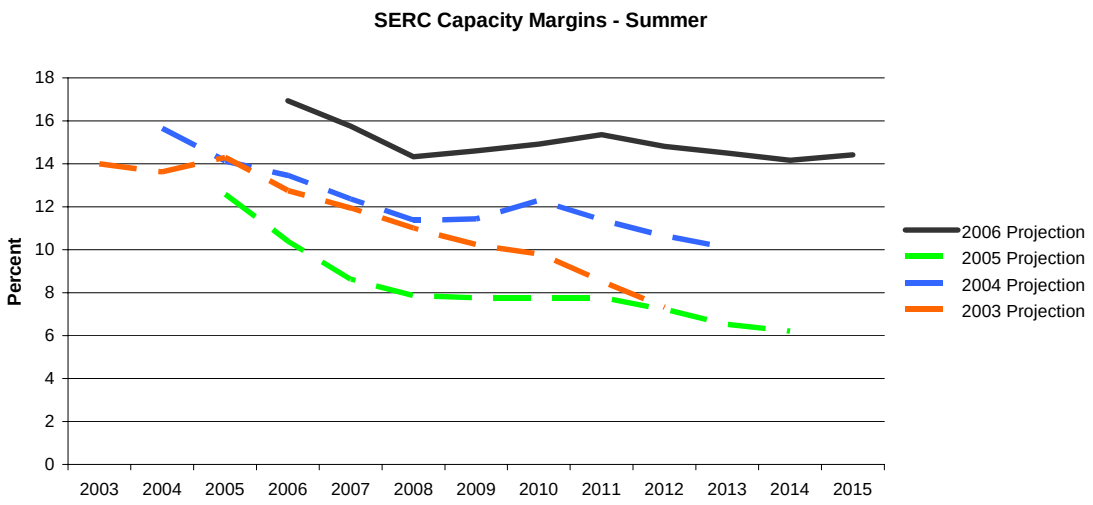


Figure 40: SERC Capacity Versus Demand — Summer

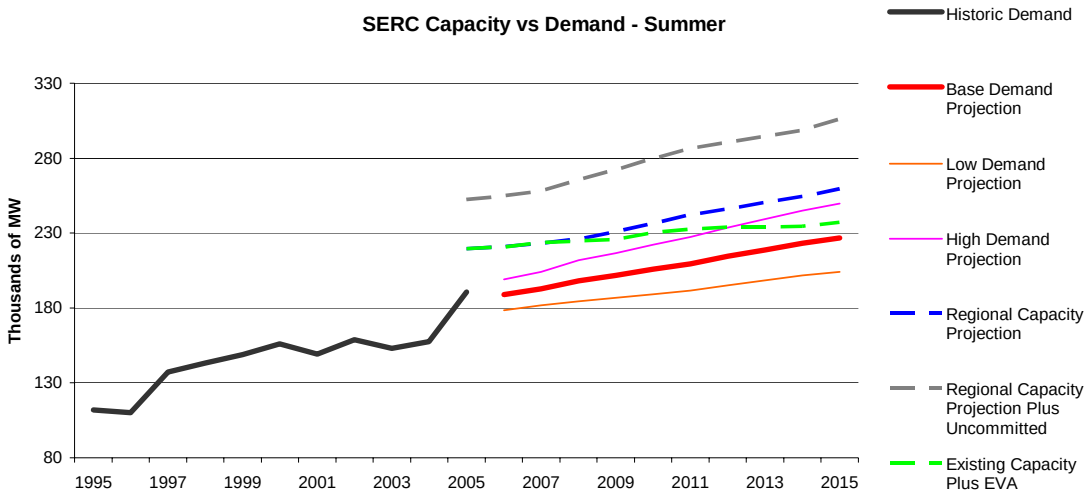
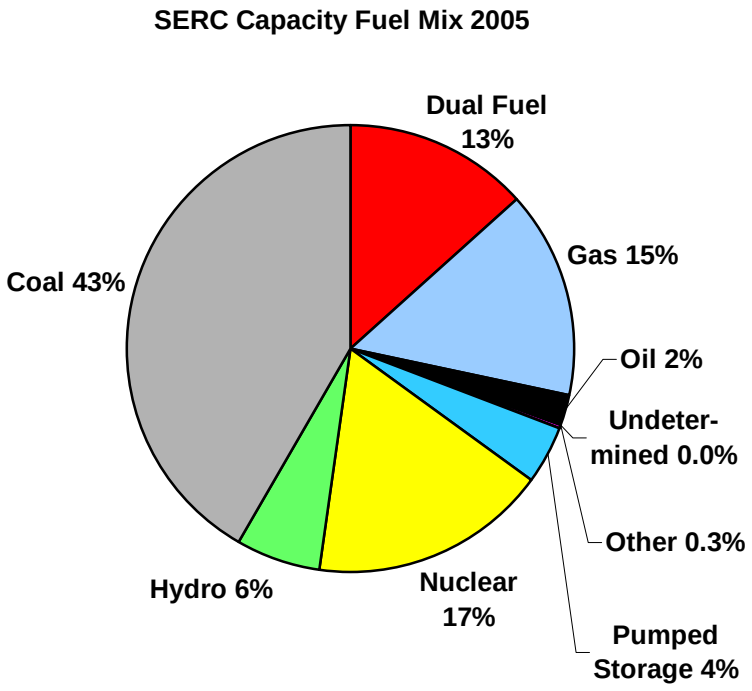
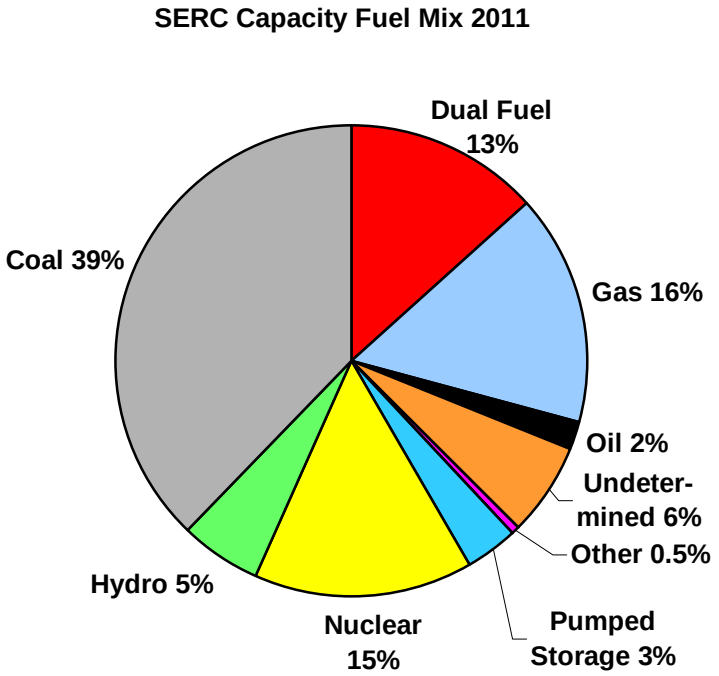


Figure 41: SERC Capacity Fuel Mix for 2005 and 2011





SPP

Demand

SPP is a summer-peaking region with a projected annual peak demand growth rate of 1.3 percent over the 2006–2015 period. This compares to last year's ten-year forecast of 1.3 percent for the 2005–2014 time frame. The forecasted growth rate is comparable to actual experience based on recent history. Although actual demand is very dependent upon weather conditions and typically includes interruptible loads, forecasted net internal demands are based on normal weather conditions and do not include interruptible loads.

Each SPP member annually provides a ten-year forecast of peak demand and net energy requirements. The forecasts are developed in accordance with generally recognized methodologies and also in accordance 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 percent in the case of extreme weather. To ensure against negative impacts due to forecast error, SPP requires a 12 percent capacity margin.

Energy

The projected annual energy growth rates is 1.3 percent per year for the 2006–2015 period. This compares to last year's ten-year forecast of 1.5 percent for the 2005–2014 time frame.

Resources

The net aggregate capacity reported by SPP members is 47,236 MW for the summer of 2007 with a mix of 38 percent coal, 36 percent gas, 8 percent dual fuel, 7 percent hydro, 4 percent nuclear, 2 percent oil, and 5 percent other.

SPP criteria requires that members maintain a 12 percent capacity margin. Expected capacity margins reflected in EIA-411 data are 16.9 percent in 2007, 17.0 percent in 2008, and 15.1 percent in 2009. The capacity margin ten-year forecast is 15.2 percent. This compares to last year's ten-year forecast of 13.6 percent. The capacity margins remain above 12 percent until 2015 when it drops to 11.1 percent. These numbers correspond closely with the ten-year average capacity margins reported last year.

Based on SPP's transactions database that may consist of firm and nonfirm data, a total of 1,550 MW of long-term sales to other regions is planned for the next ten years. This breaks down into 60 MW to ERCOT, 400 MW to WECC, 1,000 MW to SERC, and 100 MW to RFC.

A very small portion of the capacity margin depends on the purchases from other regions. A total of 1,630 MW of total purchases from other regions is planned for the next ten years. This breaks down into 220 MW from ERCOT, 1,160 MW from SERC, and 250 MW from MRO.

The capacity reported for SPP based on the EIA-411 information does not reflect 7,652 MW of merchant plants that are located in the SPP footprint. It is important to note that some of these uncommitted

resources may not be deliverable to reliably serve customer demand. Additionally, SPP expects around 10,000 MW of nameplate capacity from new merchant generation over the next ten years. The majority of these future additions are wind farms that can only be expected to contribute between zero and 20 percent of nameplate rating during summer peak load conditions.

Fuel

Fuel supply for SPP generating units is expected to be adequate. The SPP region is blanketed with major gas pipelines, which should provide adequate supply for gas-fired plants. Coal-fired plants are expected to have an adequate fuel supply in compliance with SPP criteria requiring sufficient quantities of standby fuel. SPP hydro reservoirs are anticipated to be abundant, although the energy output from hydro is not projected to have regional impact given that only 7 percent of SPP capacity is hydro based.

Transmission

SPP held its 2006 Regional Transmission Expansion Planning Summit in Kansas City, Missouri, on May 18th with over 120 participants. SPP's planning process was recently shortened to a 12-month cycle with an initial reliability assessment to be followed with a commercial/economic based assessment. SPP staff presented the results of an analysis that identified locations where the SPP system will require reinforcements for years 2011–2016. SPP solicited feedback and recommendations from all stakeholders.

Key areas of system improvement focus include the north Arkansas, Missouri area where transmission improvements are needed as a result of rapid load growth such as in the northwest Arkansas/Fayetteville area. West Oklahoma and north Texas is another focus area of unexpected load growth due to recent increase in the gas and oil prices.

Currently, SPP members are investing approximately $250 million in transmission expansion projects, which will be completed in 2006–2007. Several significant EHV transmission expansion projects are expected in SPP in the near future. In addition to reliability projects, SPP members are sponsoring system upgrades to mitigate congestion and improve economic efficiencies. The most recent nonreliability-based system upgrades to the SPP network include:

- LaCygne-West Gardner 345-kV line — reconductored April, 2006
- Redbud-Arcadia 345-kV lines — replaced three 345-kV circuit breakers and ten 345-kV switches at the Arcadia substation in May, 2006

Planned transmission upgrades of regional significance addressing system load growth and capacity needs include the following:

- McDowell 230/115-kV transformer, fall 2006
- Tulsa area 345-kV and 138-kV expansion projects, summer 2007
- Seven Rivers-Pecos-Potash Junction 230-kV line and Pecos 230/115-kV transformer, spring 2008
- Paola 345/161-kV transformer, summer 2008
- Lubbock South 230/115-kV transformer, summer 2009
- Nichols 230/115-kV transformer, winter 2010
- Northwest Arkansas 345-kV and 161-kV expansion in 2007 and 2010
- East Centerton 345/161-kV transformer, summer 2011
- Auburn 230/115-kV transformer, summer 2012

A comprehensive reliability assessment for the 2006 SPP RTO expansion plan is well under way. The 2006 SPP Expansion Planning Summit was an important step to get the stakeholders involved in the expansion planning process. The next step is for SPP to analyze plans submitted by stakeholders and SPP

staff to determine the recommended reinforcements for the SPP expansion plan. Once the feedback has been incorporated, the report will be sent to the SPP Board of Directors for approval.

Several other special studies are being conducted, including:

- Ozark Study (N.W. Arkansas, SW Missouri)
- Kansas Security Constrained Unit Commitment Study
- Texas/Oklahoma Study (Panhandle area)
- NE Texas/N.W. Louisiana Study
- SPP/ERCOT (W. Texas)
- Acadiana Study (S. Louisiana)
- Entergy Louisiana Study

SPP continues to assess the general reliability of the transmission network for the 1–5 year time frames in accordance with applicable NERC planning standards. SPP members will identify transmission plan to address their reliability needs out to the five-year study horizon.

Operations

SPP has operated a reliability coordination center since 1997. The reliability coordination center provides the exchange of near real-time operating information and around-the-clock reliability coordination. Currently, no major generator unit or transmission outages affecting reliability in an adverse manner are anticipated over the next ten years for SPP.

Even though no operational issues are anticipated, SPP is reviewing regional operating practices and the influence they might have on long-term regional system reliability improvements. Additionally, SPP recently completed a scheduled five-year review of the underfrequency load shed program anticipating a renewal of its defined load shed response as regional criteria.

SPP has experienced TLR curtailments on its transmission facilities in recent years and expects that this will continue in the future. Although SPP has adequate transmission to reliably serve native load, it expects heavy use of the transmission system for economy transactions to continue into the future.

SPP operates an automatic reserve sharing program as a sub-function of the regional operating reserve criteria. Requirements in which regional participation ensures necessary capacity reserves are available on a daily basis for unexpected loss of generation. The automatic reserve sharing program meets NERC operating policy.

SPP continues to work with neighboring entities to implement effective seams agreements to facilitate coordinated operations and planning.

No known environmental and/or regulatory restrictions are expected to impede reliability during the summer months.

Assessment Process

The SPP engineering group prepares SPP's submittal to the *NERC Long-Term Reliability Assessment*. The Transmission Working Group (TWG), a committee that is represented by SPP members and other stakeholders is responsible for publication of seasonal and future reliability assessment studies on the transmission system of the SPP region. TWG also provides oversight of coordinated planning efforts and transmission contingency evaluations. The long-range planning models used for the *NERC Long-Term Reliability Assessment* are developed by SPP's Model Development Working Group (MDWG) which is also represented by SPP members.

SPP, a reliability coordinator in the southwest quadrant of the Eastern Interconnection system, 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 comprised of 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 220 facilitates the organization's activities and services. Additional information can be found on the SPP Web site (www.spp.org).

SPP Capacity and Demand

Figure 42: SPP Net Energy for Load

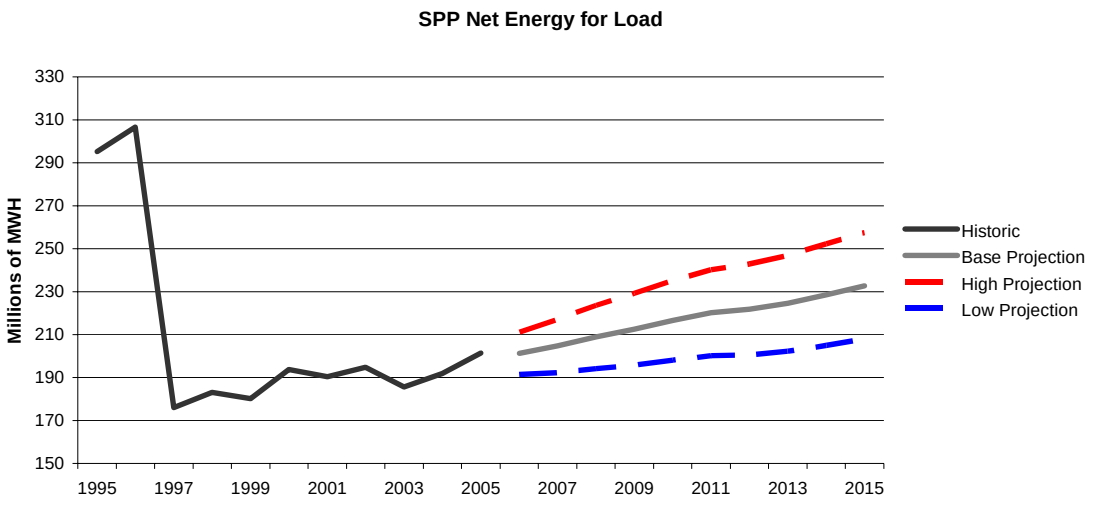


Figure 43: SPP Capacity Margins — Summer

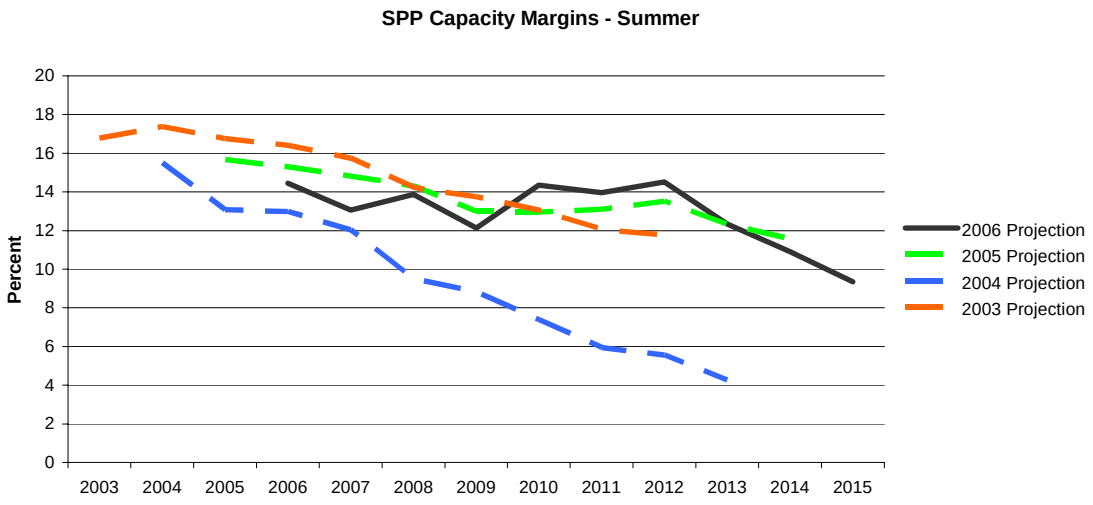


Figure 44: SPP Capacity Versus Demand — Summer

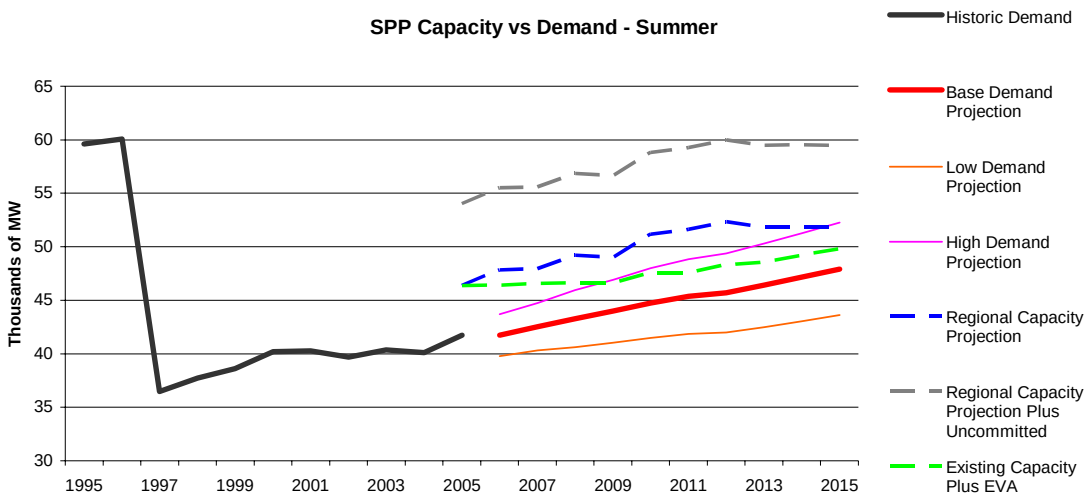
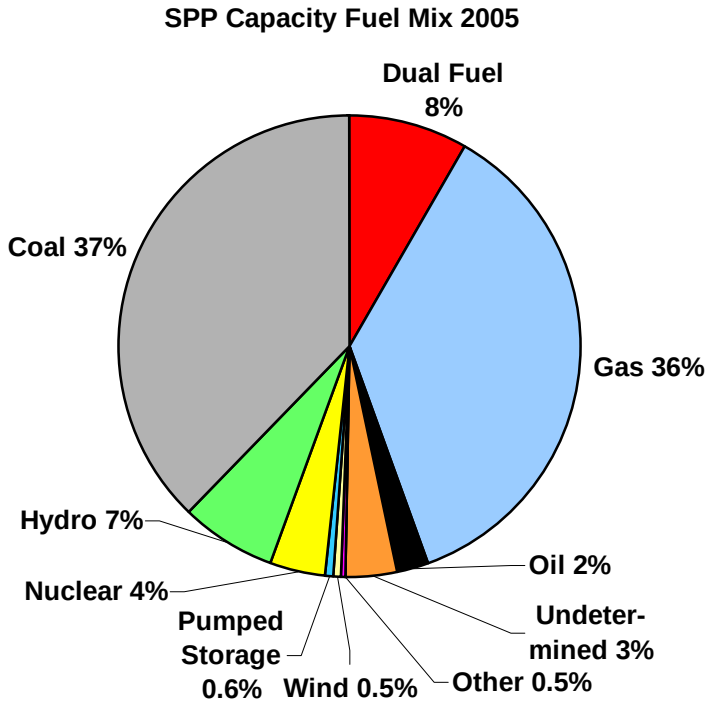
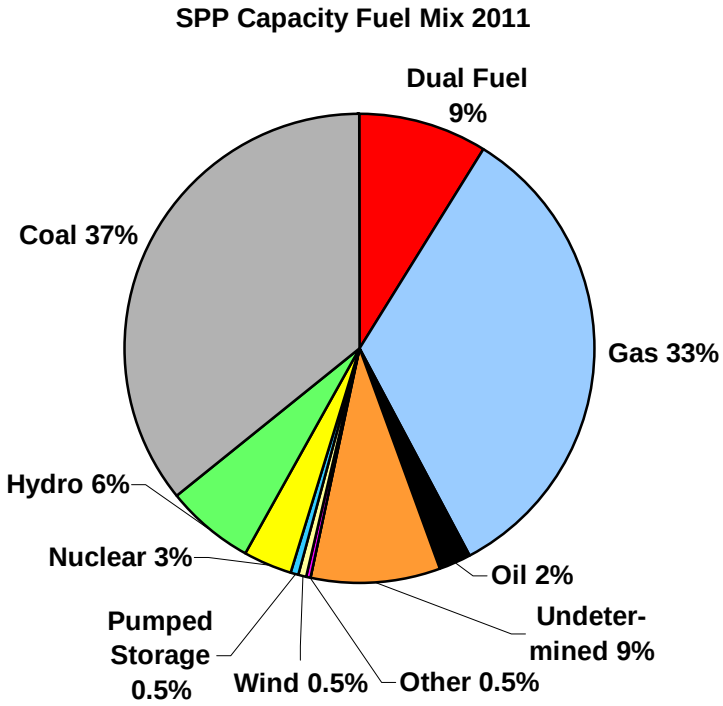


Figure 45: SPP Capacity Fuel Mix for 2005 and 2011





WECC

Demand

Total internal demand increased by 5.7 percent from 2004 to 2005. Since the 2005 summer temperatures were warmer than normal, projected 2006 summer total internal demand is expected to increase by only 0.7 percent from 149,147 MW in 2005 to 150,177 MW in 2006. Thereafter, summer total internal demand is expected to increase by about 2.2 percent per year compared to 2.4 percent projected last year for 2005–2014.

Demand response and interruptible loads are about 3,070 MW, with about 2,060 MW of the 3,070 MW in California. It should be noted that capacity margins are measured against net internal demand, not total internal demand.

WECC's *2006 Power Supply Assessment Report* (PSA) indicates that summer peak demands may increase region-wide by about an additional 2,100 MW above the forecasted peak and about 2,530 MW above the forecasted 2015 peak, should the region experience a hot spell, similar to that experienced on July 9, 1985. For the winter period, a region-wide increase of almost an additional 2,570 MW in 2006–2007 to about an additional 3,030 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998. The above peak demand weather sensitivities are equivalent to roughly one year or less of normal expected demand growth.

WECC has not established an interconnection-wide process for addressing the issue of planning for peak demand uncertainty and variability in demand due to weather and other conditions. Individual entities within the interconnection, however, have addressed multiple uncertainties and variability issues as a part of either their integrated resources plan procedures or other similar processes. Those various independent processes generally report that maintaining a reserve margin in the mid-teens would provide sufficient cushion relative to multiple uncertainties.

Energy

Annual energy usage increased by 1.9 percent from 816,079 GWh in 2004 to 831,570 GWh in 2005. The 2005 energy usage was 1.2 percent lower than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2005 through 2015 was forecasted to increase by 2.0 percent compared to the historic annual energy usage increase of 1.9 percent from 1995 through 2005. Annual energy usage for the nine-year period from 2006 through 2015 is forecast to increase by 2.2 percent.

Resources

WECC has not established an interconnection-wide process for assessing resource adequacy. Individual entities within the interconnection, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process. Entities within the interconnection have not reported changes in generation/resource planning brought about by the Eastern Interconnection blackout.

The WECC resource data is reduced to reflect nonmetered self-generation and expected wind and adverse hydro limitations. The uncommitted resources reflect reported resource additions that are not under construction or are under construction with reported in-service dates after July 2007 (or July 2008 if coal fired).

Other announced generic resource additions and, generally, projects without identified locations and/or in-service dates, are excluded from the committed and uncommitted resource data. The resource data for the individual WECC-U.S. systems subregions include a potential utilization of seasonal demand diversity between the winter-peaking northwest and the summer-peaking southwest. To avoid double

counting of resources, the WECC-U.S. systems net capacity resource totals do not include the diversity utilization. Utilization of the seasonal demand diversity may be limited due to factors such as internal transmission constraints.

WECC's PSA reports that by 2009 summer transfer capability limitations between the northern and southern portions of the Western Interconnection result in a 1,000 MW resource shortfall. The southern portion resource needs increase to roughly 20,000 MW by 2015, even though the northern portion is capacity surplus throughout the period. Although the transmission limitations represented in the PSA analysis are conservative, they are not unreasonable and the report establishes that WECC has insufficient transmission to fully utilize seasonal capacity/demand diversity within the Western Interconnection. A 1,600 MW undersea dc cable has been proposed to interconnect a substation near Portland, Oregon, and the San Francisco Bay area. Completion of the 650-mile interconnection would allow additional California imports of low-cost and renewable electricity from the northwest.

The net resource addition of 20,720 MW used in this report is composed of 6,599 MW of plants under construction and 15,938 MW of plants identified but not presently under construction. The regulatory and financial status of these projects is not known at this time. If the 1,817 MW of planned retirements and other derates occur as scheduled and if no plants are built beyond those already under construction, the WECC capacity margin would drop from 19.4 percent in the summer of 2007 to 11.3 percent by the summer of 2011.

In the near term, WECC entities report firm purchases from Eastern Interconnection entities of about 500 MW, partially offset by firm sales of about 200 MW. By the summer of 2015, purchases decline to about 300 MW and sales decline to about 200 MW.

Fuel

WECC has not implemented a formal fuel supply interruption analysis methodology and does not consider such conditions in any formal assessment process. 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. While a few of the older gas-fired generators in the region have backup fuel capability and normally carry an inventory of backup fuel, most of the newer generators are strictly gas-fired plants, increasing the region's exposure to interruptions to that fuel source. This is particularly true for California, which is highly reliant on gas-fired generation and has only three plants that maintain dual-fuel capability.

The natural gas supply system within WECC is fairly robust and the region is not highly dependent on external natural gas supplies. However, the western gas transmission system is interconnected with external transmission systems so gas deliveries can be redirected to other regions. Many individual entities have fuel supply interruption mitigation procedures in place, including on-site coal storage facilities. However, on-site natural gas storage is generally impractical so gas-fired plants rely on the general robustness of the pipeline delivery system and firm supply contracts. WECC does not impose fuel supply requirements on its members.

Transmission

Transmission facilities are planned in accordance with NERC and WECC planning standards. Those standards establish performance levels intended to limit the adverse effects of each transmission system's operation on others and recommend that each system provide sufficient transmission capability to serve its customers, to accommodate planned interarea power transfers, and to meet its transmission obligation to others.

The standards do not require construction of transmission to address intraregional transfer capability constraints. WECC, in conjunction with MRO and SPP, studies intra-area power transfer capabilities. During the study period, entities within WECC plan to add 5,951 miles of transmission lines.

Operations

Under WECC's regional reliability plan, three reliability centers have been established for the region in California, Colorado, and Washington. The reliability coordinators are charged with actively monitoring, on a real-time basis, the interconnected system conditions on a wide-area basis to anticipate and mitigate potential reliability problems and to coordinate system restoration should an outage occur.

The blackout in the Eastern Interconnection has increased awareness regarding ongoing tree trimming programs, and several entities within WECC have reported increased long-range transmission right-of-way clearance work.

WECC operations personnel are progressing on implementing an interconnected system operating condition model.

Significant amounts of thermal generation within WECC are subject to air emission limitations. The limitations may adversely affect operating costs and flexibility but are not expected to reduce margins.

No extended major unit outages or temporary operating measures have been reported that may impact reliability for extended periods over the next ten years. Operational issues are expected to center around issues such as transmission congestion management, hydroelectric energy generation limitations, and integration of renewable resources.

Assessment Process

Each year WECC prepares a transmission study report that provides an ongoing reliability-security assessment of the WECC interconnected system in its existing state and for system configurations planned through the next ten years. The disturbance simulation study results are examined relative to NERC and WECC planning standards. If study results do not meet expected performance levels established in the criteria, the responsible organizations are obligated to provide a written response that specifies how and when they expect to achieve compliance with the criteria. Other measures that have been implemented to reduce the likelihood of widespread system disturbances include: an islanding scheme for loss of the AC Pacific Intertie that separates the Western Interconnection into two islands and drops load in the generation-deficit southern island; a coordinated off-nominal frequency load shedding and restoration plan; measures to maintain voltage stability; a comprehensive generator testing program; enhancements to the processes for conducting system studies; and a reliability management system.

- Operating Transfer Capability Policy Committee Process

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

On the basis of these ongoing activities, transmission system reliability within the Western Interconnection is expected to meet NERC and WECC standards throughout the ten-year period.

Northwest Power Pool Area

Demand — The Northwest Power Pool (NWPP) area is comprised of all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming; a small portion of northern California; and the Canadian provinces of British Columbia and Alberta. For the period from 2006 through 2015, winter total internal demands are projected to grow at annual compound rates of 1.6 percent and 1.9 percent in the United States and Canadian areas, respectively.

WECC's 2006 PSA indicates that summer peak demands may increase by about an additional 490 MW in 2006 to about 565 MW in 2015 should the region experience a hot spell similar to that experienced on July 9, 1985. For the winter period, an increase of almost an additional 1,940 MW in 2006–2007 to about an additional 2,230 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998.

Energy — Annual energy usage increased by 3.9 percent from 347,313 GWh in 2004 to 360,889 GWh in 2005. The 2005 energy usage was 1.9 percent greater than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2005 through 2015 is forecast to increase by 1.9 percent compared to the historic annual energy usage increase of 1.3 percent from 1995 through 2005. Annual energy requirements are projected to grow at annual compound rates of 1.9 percent and 2.1 percent in the U.S. and Canada areas, respectively.

Resources — The data for the United States portion of the NWPP present winter 2007/2008 capacity margins of 28.4 percent without uncommitted resources and 30.0 percent with uncommitted resources. By winter 2011/2012, those margins change to 23.7 percent and 30.3 percent, respectively. For the Canadian portion of the NWPP, the winter 2007/2008 capacity margins are 7.6 percent without uncommitted resources and 9.4 percent with uncommitted resources. By winter 2011/2012, those margins decline to -1.1 percent without uncommitted resources and 5.1 percent with uncommitted resources. The Canadian entities are aware of the resource adequacy issue for their areas and have instituted very active resource acquisition and transmission reinforcement processes.

NWPP planning is conducted by sub-area. Idaho, northern Nevada, Wyoming, Utah, British Columbia, and Alberta individually optimize their resources to their demand. The coordinated system (Oregon, Washington, and western Montana) coordinates the operation of its hydro resources to serve its demand. In 2001, the northwest experienced its second lowest Coordinated Columbia River System volume runoff since record keeping began, with reservoirs refilling to just 71 percent of capacity, the lowest levels in almost a decade. Since 2001, the reservoir refill has ranged between 87 percent and 92 percent of capacity.

The reservoirs are managed to address all of the competing requirements including but not limited to: current electric power generation, future (winter) electric power generation; flood control; fish and wildlife requirements; special river operations for recreation; irrigation; navigation; and refilling of the reservoirs. In addition to managing the competing requirements, other available generating resources, market conditions, and load requirements are considered and incorporated into the decision for refilling the reservoirs. Any time precipitation levels are below normal, balancing these interests becomes even more difficult. A ten-year agreement was reached in 2000 among parties involved in operation of the Columbia River Basin concerning river operations. However this agreement is subject to three-, five-, and eight-year performance checks and reopening by the parties. The net impact of the agreement is a reduction in generating capability as a result of hydro generation spill policies designed to favor fish migration. The capability reduction, which varies depending on water flows and other factors, is reflected in the margin calculations presented in this report. The agreement includes a provision for negotiating changes in the plan under emergency conditions as occurred in 2001.

Generation in the province of Alberta, Canada, operates in a fully deregulated market and thus resource additions are market driven. Generation additions and load growth are expected to result in some transmission constraints in a number of areas over the course of the review period if identified system reinforcements are not completed on time. The impact of most of these constraints is anticipated to be local in nature and will not impact the transmission systems outside of Alberta.

The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process. Entities within the subregion have not reported changes in generation/resource planning brought about by the Eastern Interconnection blackout.

Fuel — A significant portion of the electric power generated in the Pacific Northwest is derived from hydroelectric generation. Hence, wide variations in annual precipitation, water storage and flow limitations, and other factors significantly affect energy generation from other resources and complicate the fuel planning processes. Coal-fired generation in the area is also very significant. Much of the coal-fired generation has near-fuel sources and is often operated in a base-load mode. Consequently, the area is not highly reliant on gas-fired plants relative to annual energy generation and many of those plants are more often operated as seasonal peaking units. Wind-powered generation is increasing rapidly in the area. Since the wind resources exhibit wide fluctuations in output, areas with relatively large amounts of wind-powered generation are investigating potential interconnection limitations as necessary to minimize adverse consequences that may occur.

Transmission — In view of the longer time required for transmission permitting and construction, it is recognized that network planning should focus on establishing a flexible grid infrastructure. This is being done with the goals of allowing anticipated transfers among NWPP systems, addressing several areas of constraint within Washington, Oregon, Montana, and other areas within the region, and integrating new generation. Projects at various stages of planning and implementation include approximately 986 miles of 500-kV transmission lines.

Maintaining the capability to import power into the Pacific Northwest during infrequent extreme cold weather periods continues to be an important component of transmission grid operation. In order to support maximum import transfer capabilities under double-circuit simultaneous outage conditions, the northwest depends on an automatic underfrequency load shedding scheme.

Approvals for two major system developments have been received from the Alberta provincial regulatory authority. The first of these is for the development of approximately 105 kilometers (65 miles) of 240-kV transmission line to accommodate several new wind generation developments in southwest Alberta. This development has an in-service date of 2007.

The second approval is for the construction of a 500-kV line, approximately 330 kilometers (200 miles) in length, to strengthen the main north-south transmission grid. This development has a proposed in-service date of 2009. In conjunction with this project, approval to install 520 Mvar of capacitor banks in the Calgary area has also been received. The capacitor banks were placed in service at the end of 2005.

A Calgary area transmission must run (TMR) procedure has been updated to address the 240-kV transmission grid-loading issues and to ensure that voltage stability margins are maintained. The TMR service is an ancillary service contract with generators that is required to address contingencies in areas of inadequate transmission to help provide voltage support to the transmission system in southern Alberta, near Calgary, and assist in maintaining overall system security.

Increased local area load has reduced the export capability of the Alberta-Saskatchewan dc tie. A planning study is currently under way to analyze the Empress area and the Alberta-Saskatchewan dc tie

export capability. The study and recommendations are expected to be completed by December 2006. Applications for additional transmission developments will be filed as required.

The Canadian province of British Columbia relies on hydroelectric generation for 90 percent of its resources. British Columbia Hydro and Power Authority is addressing constraints between remote hydro plants and lower mainland and Vancouver Island load centers. The definition phase of a new 500-kV line between Nicola and Meridian substations and a 230-kV underwater cable between Arnott substation and Vancouver Island terminal is under way.

The new 500-kV line will increase the total transfer capability of the interior to lower mainland area grid and the new 230-kV cable will increase the transfer capability from the lower mainland area to Vancouver Island. These projects have proposed in-service dates of 2013 and 2008, respectively.

Proposed NWPP Projects > 50 Miles	Status	Date
Cordell, AB to Metiskow, AB 240-kV line	Completed	November 2005
Ellensburg, WA to Sunnyside WA 500-kV line	Completed	December 2005
Goose Lake to N. Lethbridge, AB 240-kV line	Permitting	2007
Benewah, ID to Shawnee, WA 230-kV line	Planning	2007
Montana-Alberta 230-kV merchant line	Permitting	2007
American Falls, ID to Hunt, ID 230-kV line	Under way	2007
Vancouver Island-Arnott 230-kV line	Planning	2008
Keephills-Genesee-Ellerslie, AB 500-kV line	Permitting	2009
Genessee, AB to Langdon, AB 500-kV line	Permitting	2009
Cranbrook, BC to Invermere, BC 230-kV line	Planning	2011
Mona, UT to Salt Lake, UT 345-kV line	Planning	2007/2011
Nicola, BC to Meridian, BC 500-kV	Planning	2013
Southwest Intertie project (ID-NV 260 mile tie)	Planning	2013

Operations — Under normal weather conditions, the NWPP does not anticipate dependence on imports from external areas during summer peak demand periods. In the event of either extreme weather or much lower than normal precipitation, the NWPP could increase imports, which would reduce reservoir drafts and aid reservoir filling. Off-peak energy transfers allow southwest generators to increase thermal plant loading during normally light load hours to offset to some extent the effects of any adverse hydro conditions.

WECC's 2006 PSA report notes that transmission constraints exist between the United States and Canadian portions of the NWPP and that by 2015 over 3,000 MW of additional capacity (generation or transmission for imports) will be needed in Canada. Both provinces are addressing the capacity issue. For example, British Columbia recently announced the awarding of a few dozen contracts representing over 1,500 MW of capacity.

Rocky Mountain Power Area

Demand — The Rocky Mountain Power Area (RMPA) consists of Colorado, eastern Wyoming, and portions of western Nebraska and South Dakota. The RMPA may experience its annual peak demand in either the summer or winter season due to variations in weather. For the period from 2006 through 2015, summer total internal demands and annual energy requirements are projected to grow at annual compound rates of 2.4 percent and 2.2 percent, respectively.

WECC's 2006 PSA report indicates that summer peak demands may not increase should the region experience a hot spell similar to that experienced on July 9, 1985. For the winter period, an increase of

almost an additional 50 MW in 2006–2007 to about an additional 60 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998.

Energy — Annual energy usage increased by 3.4 percent from 57,214 GWh in 2004 to 59,190 GWh in 2005. The 2005 energy usage was 4.3 percent less than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2005 through 2015 is forecast to increase by 2.1 percent compared to the historic annual energy usage increase of 3.1 percent from 1995 through 2005. Annual energy usage for the nine-year period from 2006 through 2015 is forecast to increase by 2.2 percent.

Resources — The data for the Rocky Mountain Power Area (RMPA) present the summer 2007 capacity margins of 9.8 percent without uncommitted resources and 13.2 percent with uncommitted resources. By the summer of 2011, those margins become -0.8 percent and 15.5 percent, respectively. A significant portion of the expected uncommitted resources has received state utility commission approval and is under active development.

Due to extended drought, hydro generation is at low levels along the North Platte River. The low flows have impacted cooling water availability at a major coal-fired plant, requiring acquisition of groundwater rights as a supplemental water source. Water levels in Lake Powell, which is the reservoir for Glen Canyon dam generation, are expected to end the 2006 water year 70 feet below full. This results in a capacity reduction of about 170 MW (14 percent) due to a lower hydraulic head at the plant.

Tri-State Generation and Transmission Association announced plans in late 2005 to construct two 600 MW coal-fired units at the Holcomb generator site near Garden City, Kansas. Plant in-service dates are slated for a 2012–2013 time frame. Basin Electric Power Cooperative is developing the Dryfork 385 MW coal plant near Gillette, Wyoming, with a 2011 in-service date. Public Service Company of Colorado (PSC) is in the process of a request for proposals (RFP) for new resources to meet its needs through 2010. PSC already has 300 MW of wind generation integrated into its system as of 2006. PSC has received approval to construct a 750 MW coal-fired plant at the existing Comanche station in 2010, and plans on adding 1,600 MW of other resources over the next five years. The RMPA margins referred to above do not include the possible 1,600 MW resource additions.

The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process.

Fuel — Coal, hydro, and gas-fired plants are the dominant electricity sources in the area. Much of the coal is provided by relatively nearby mines and is often procured through long-term contracts. Hydroelectric plants, however, may experience operational limitations due to variations in precipitation. As in the northwest, gas-fired plants are most often operated in a peaking mode. Abundant natural gas supplies exist within the area but delivery constraints may occur at some plants during unexpected severe cold weather conditions.

Transmission — The Western Area Power Administration (WAPA) plans to upgrade several 115-kV transmission lines to 230 kV over the next ten years to increase transfer capabilities and to help maintain the operating transfer capability between southeastern Wyoming and northeastern Colorado. In addition to those conversions, the table below describes additional transmission projects.

Proposed RMPA Projects > 50 Miles	Status	In-service Date
Carr Draw-Hartzog-Teckla, WY 230-kV lines	Completed	November 2005
Walsenburg, CO to Gladstone, NM 230-kV line	Under way	Late 2007
Hughes, WY to Sheridan, WY 230-kV line	Planned	2008
San Luis Valley-Walsenburg, CO 230-kV line	Planned	2009
Upgrades to Path 36 (TOT3) between southeast Wyoming and northeast Colorado	Under way	2009
Comanche-Daniels Park #1 & #2 345-kV lines	Planned	May 2009
Beaver Creek-Erie #2 230 kV	Under way	2010
Holcomb, KS to Front Range, CO 500 kV	Planned	2011

Operations — Transmission upgrades in the area have alleviated some transfer capability limitations, but some system constraints remain. Operator flexibility will be limited by the transmission constraints and operating conditions must be closely monitored, especially during periods of high demand. In some cases, special protection schemes are utilized to preserve system adequacy should multiple outage contingencies occur.

Arizona-New Mexico-Southern Nevada Power Area

Demand — The Arizona-New Mexico-Southern Nevada (AZ-NM-SNV) power area consists of Arizona, most of New Mexico, southern Nevada, the westernmost part of Texas, and a portion of southeastern California. For the period from 2006 through 2015, summer total internal demands and annual energy requirements are projected to grow at annual compound rates of 2.9 percent.

WECC's 2006 PSA report indicates that summer peak demands may increase by about an additional 45 MW in 2006 to about 55 MW in 2015 should the region experience a hot spell similar to that experienced on July 9, 1985. For the winter period, an increase of almost an additional 50 MW in 2006–2007 to about an additional 65 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998.

Energy — Annual energy usage increased by 2.9 percent from 122,940 GWh in 2004 to 126,540 GWh in 2005. The 2005 energy usage was 1.0 percent greater than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2005 through 2015 was forecasted to increase by 2.8 percent compared to the historic annual energy usage increase of 3.7 percent from 1995 through 2005. Annual energy usage from 2006 through 2015 is forecast to increase by 2.9 percent.

Resources — The data for this sub-area present the summer 2007 capacity margins of 19.6 percent without uncommitted resources and 19.8 percent with uncommitted resources. By the summer of 2011, those margins become 8.4 percent and 13.7 percent, respectively. As in the RMPA, a significant portion of the uncommitted resources has received state utility commission approval and is under active development.

As with other areas within WECC, the future adequacy of the generation supply over the next ten years in this area will depend on how much new capacity is actually constructed. Generally, the proposed plants have relatively short construction times once the decision is made to proceed, although an expansion of the Springerville coal-fired plant is under way with one unit under construction and an additional unit scheduled to be in commercial operation by late 2009. Frequently, resource acquisitions are subject to a request for proposal process that may increase the uncertainty regarding plant type, location, etc. These factors combine to make generation adequacy forecasting problematic for an extended period of time.

The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process.

Fuel — Coal, hydro, and nuclear plants are the dominant electricity sources in the area. As in the northwest, gas-fired plants are most often operated in a peaking mode. Much of the coal is provided by relatively nearby mines and is often procured through long-term contracts. Major hydroelectric plants are located at dams with significant storage capability so short-term variations in precipitation are not a significant factor in fuel planning.

Transmission — Transmission providers from the AZ-NM-SNV Power area are actively engaged in the Southwest Transmission Expansion Planning (STEP) group along with stakeholders from southern California. The goal of this group is to participate in the planning, coordination, and implementation of a robust transmission system between the Arizona, southern Nevada, Mexico, and southern California areas that is capable of supporting a competitive, efficient, and seamless west-wide wholesale electricity market while meeting established reliability standards. Three projects have resulted from the study efforts to upgrade the transmission path from Arizona to southern California and southern Nevada. The three projects will increase the transmission path capability by about 3,000 MW. The first set of upgrades will increase the transfer capacity by 505 MW and will be completed in 2006. The second set of upgrades will increase the transfer capacity by 1,245 MW and is scheduled to be completed in 2008. The last set of upgrades is the Palo Verde to Devers #2 500-kV transmission line reported in the California-Mexico power area table.

Proposed AZ/NM/SNV Projects > 50 Miles	Status	In-service Date
Harry Allen, NV to Mead 500-kV line	Under way	2007
Stirling Mt-Northwest-Vista, NV 230-kV line	Planned	2007
Palo Verde-TS5 500-kV line	Permitted	2009
Palo Verde to Southeast Valley (Phoenix area)	3 Parts	2011
A. Hassayampa to Pinal West 500-kV line	Under way	2008
B. Pinal West to Santa Rosa 500-kV line	Under way	2008
C. Santa Rosa to Browning 500-kV line	Permitted	2011
Centennial II (Las Vegas, NV area) 500-kV line	Planning	2011
TS5-Raceway 500-kV line	Planning	2012
Pinal West-Tortolita, AZ 500-kV line	Planning	2012
Palo Verde-North Gila 500-kV line	Planning	2012
Shiprock, NM to Marketplace, NV 500-kV line	Permitted	2010/2013
Northern to central New Mexico 345-kV generation outlet lines	Planning	2013
Greenlee-Springerville, AZ #2 345-kV line	Planning	2014
Tucson, AZ area 345-kV reinforcements	Planning	2014
Nogales, AZ to Sahuarita, AZ 345-kV lines	Planned	2014

Operations — Special protection schemes play an important role in maintaining system adequacy should multiple system outages occur. These schemes include generator tripping in response to specific transmission line outages. In addition, operators rely on procedures such as operating nomograms so that the system can respond adequately to planned and unplanned transmission and/or generation outages.

California-Mexico Power Area

Demand — The California-Mexico power area encompasses most of California and the northern portion of Baja California, Mexico. Summer total internal demands are currently projected to grow at annual compound rates of 1.9 percent and 4.5 percent in the United States and Mexican areas, respectively, from

2006 through 2015. Annual energy requirements are projected to grow at annual compound rates of 1.9 percent and 5.1 percent in the U.S. and Mexican areas, respectively.

WECC's 2006 PSA report indicates that summer peak demands may increase by about an additional 1,565 MW in 2006 to about 1,910 MW in 2015 should the region experience a hot spell similar to that experienced on July 9, 1985. For the winter period, an increase of almost an additional 530 MW in 2006–2007 to about an additional 675 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998.

Energy — Annual energy usage decreased by 1.3 percent from 288,612 GWh in 2004 to 284,951 GWh in 2005. The 2005 energy usage was 5.2 percent less than the forecast in last year's assessment, due to generally mild weather conditions throughout much of the year. Annual energy usage for the ten-year period from 2005 through 2015 was forecasted to increase by 1.8 percent compared to the historic annual energy usage increase of 1.7 percent from 1995 through 2005. Annual energy usage for the nine-year period from 2006 through 2015 is forecast to increase by 2.1 percent.

Resources — The data for the United States portion of the California-Mexico sub-area present summer 2007 capacity margins of 13.5 percent without uncommitted resources and 13.7 percent with uncommitted resources. By summer 2011, those margins become 10.8 percent and 12.6 percent, respectively. For the Mexican portion of the subregion, the summer of 2007 capacity margins are 12.3 percent without uncommitted resources and 15.4 percent with uncommitted resources. By summer 2011, those margins become -4.8 percent and 22.3 percent,respectively. The Mexican uncommitted resources include plans for a 228 MW combined-cycle plant at San Luis Rio, Colorado, with a 2008 expected in-service date.

The summer of 2007 data for the United States portion of the California-Mexico subarea includes 2,534 MW of possible diversity utilization, of total net imports from 7,517 MW, which is below historic summer import levels. By 2011, however, the possible diversity utilization resource component is increased to 5,648 MW with total net imports at 10,445 MW. Beyond about 2011, the possible diversity utilization becomes problematic due to possible resource inadequacies in other subregions and due to possible transmission constraints.

Uncertainty surrounding responsibility to acquire resources in California has raised questions regarding future projections of generating capacity, energy production by generators, and effects of customer energy efficiency and other demand-side management programs. For example, four years ago over 45,000 MW of planned resource additions were reported for the area for the 2002–2011 ten-year period. This year's assessment reports a continued decrease to 3,160 MW for the 2006–2015 period compared to 6,783 MW reported last year for the 2005–2014 period.

The *California Energy Commission's Energy Action Plan II*, dated September 21, 2005, notes that cost effective energy efficiency is the resource of first choice for meeting California's energy needs and presents a key action item that all cost-effective energy efficiency be integrated into utilities' resource plans on an equal basis with supply-side resource options. Should this happen, loads supplied through the bulk power system will not grow as fast as projected in this report.

The state is implementing a mandatory minimum reserves requirement to achieve resource adequacy and is looking to new customer electricity metering equipment as a key component to achieving demand response goals. State entities are working together and with other entities in the Western Interconnection to address transmission planning issues.

The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process.

Fuel — California is highly reliant on gas-fired generation and has very little alternate fuel capability for these plants. California is also highly reliant on natural gas imports so gas supply is of concern to area energy planners, including the California Energy Commission. The Commission's September 21, 2005 *Energy Action Plan II Implementation Roadmap For Energy Policies* identifies eight key actions to address natural gas supply, demand, and infrastructure. The report is available at: http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

Transmission — Since the addition of several generating plants in Arizona, southern Nevada, and Mexico, the bulk power system into southern California has become increasingly congested due to the desire to increase imports from the surrounding areas. Special protection schemes have been implemented for generation connected to the Imperial Valley substation in order to relieve some of the congestion and an operating nomogram is used to limit the simultaneous operation of generating plants connected to the Imperial Valley substation and imports from CFE and Arizona. The CISO anticipates that the 500-kV interconnection between Arizona and California that connects to the Imperial Valley substation will be constrained most of the time due to increased imports from new southwest generation.

Proposed CA/MX Projects > 50 Miles	Status	Date
La Jovita Project, MX 230-kV lines	Planning	2009
Palo Verde-Devers #2 500-kV line	Permitting	2009
Imperial Valley-San Diego 500-kV line	Planning	2010
Indian Hills-Upland 500-kV line	Planning	2010
New Vincent-Mira Loma 500-kV line	Planning	2011
Tehachapi Area Transmission — 500 kV	Permitting	2010–2011

Operations — The California ISO (CAISO) is moving forward on a Market Redesign and Technology Upgrade (MRTU) program of changes to ISO market and grid operations. The CAISO has set a November 2007 launch date for the MRTU program, which includes upgrades to the CAISO's computer technology to a scalable system that can grow and adapt to future system requirements. Transmission upgrades in the area have alleviated some transfer capability limitations, but numerous system constraints remain. Operator flexibility is limited by the transmission constraints and is further impacted by forest and brush fires that often occur during high-demand periods. The CAISO and other entities within the subregion are interacting in developing an integrated transmission plan for the state to address significant constraint issues.

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 councils. 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).

WECC-Canada Capacity and Demand

Figure 46: WECC-Canada Net Energy for Load

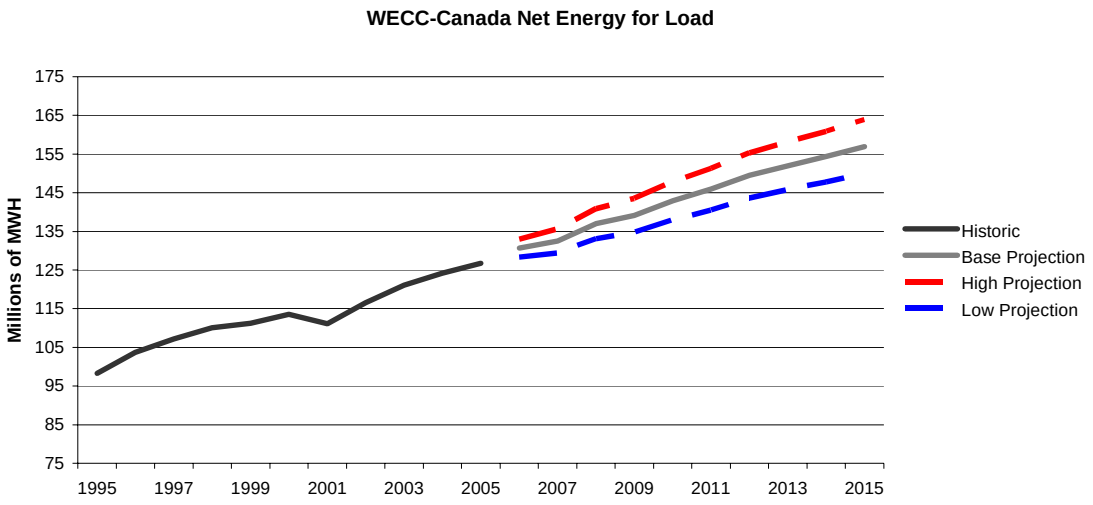


Figure 47: WECC-Canada Capacity Margins — Winter

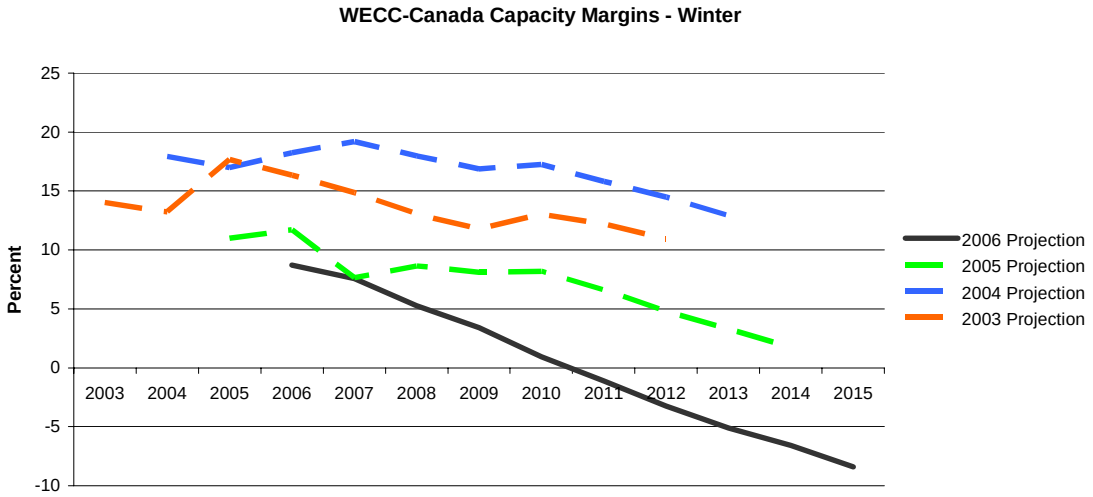
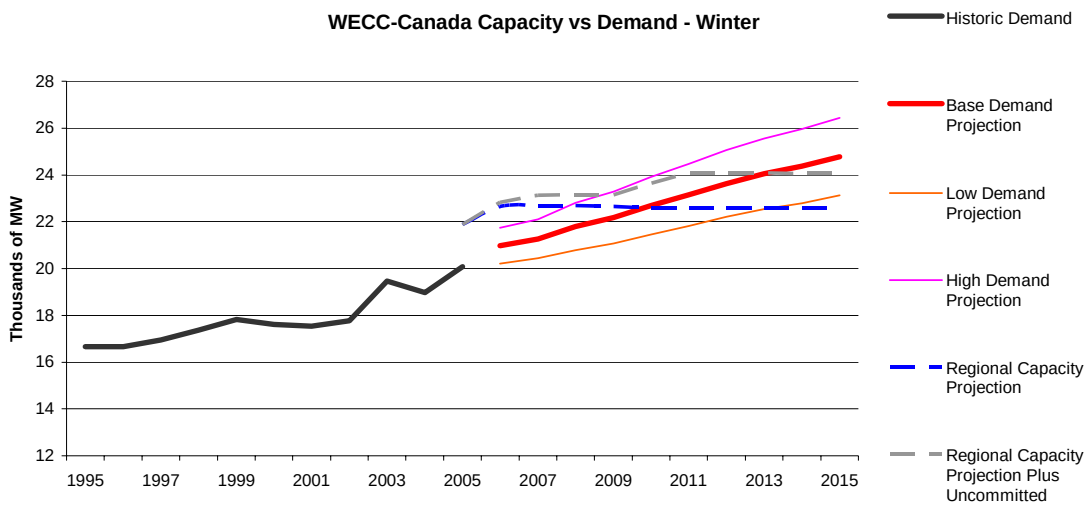


Figure 48: WECC-Canada Capacity Versus Demand — Winter



WECC-U.S. Capacity and Demand

Figure 49: WECC-U.S. Net Energy for Load

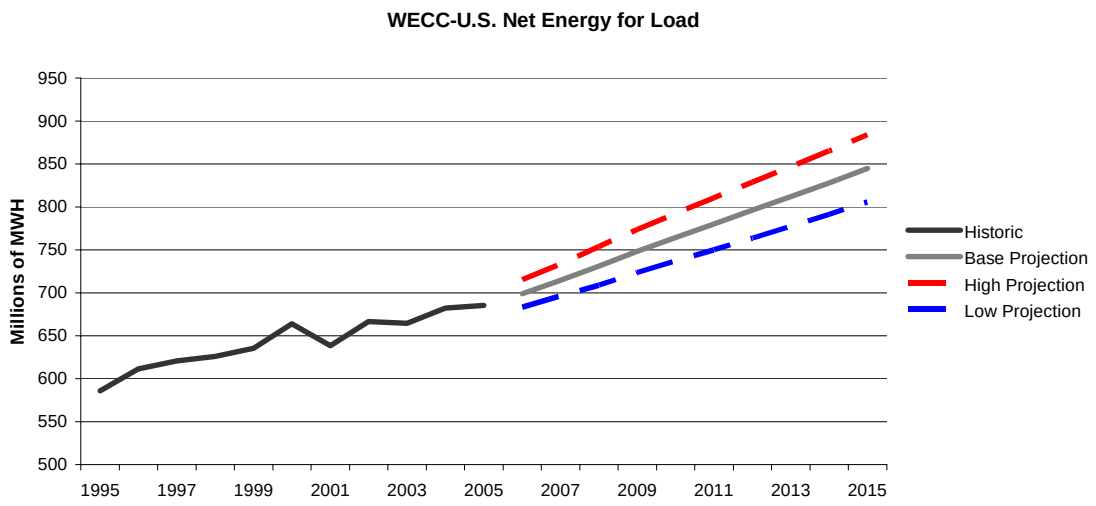


Figure 50: WECC-U.S. Capacity Margins — Summer

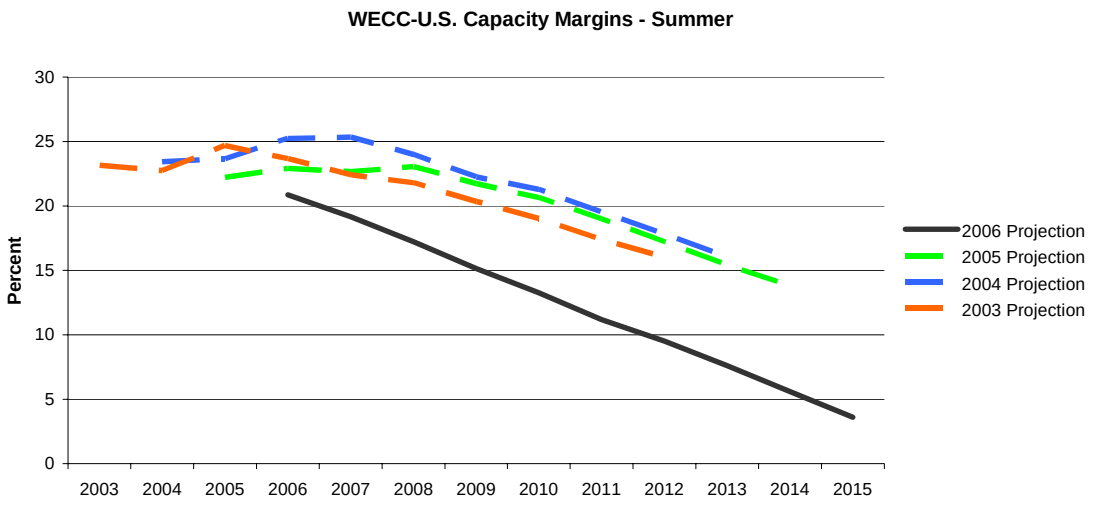


Figure 51: WECC-U.S. Capacity Versus Demand — Summer

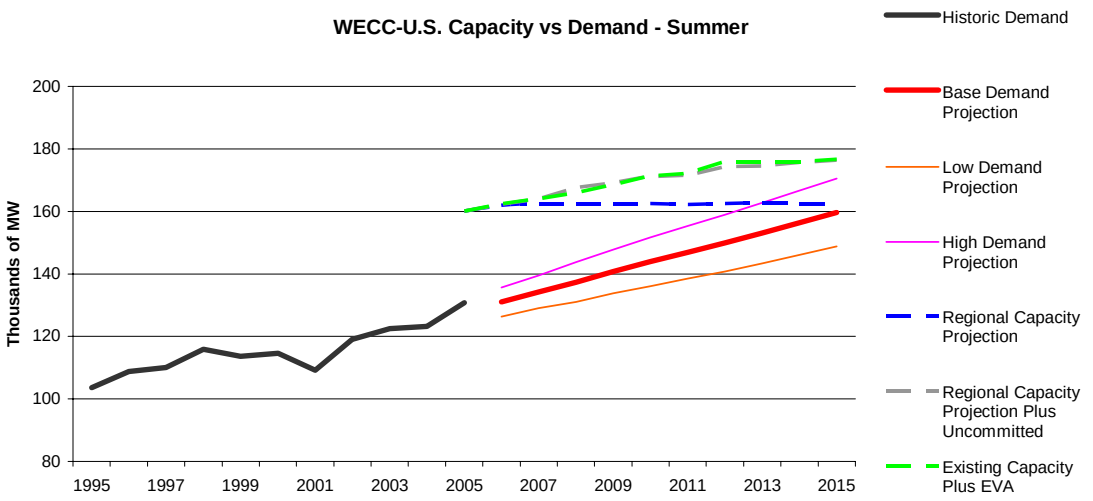


Figure 52: WECC-Canada Capacity Fuel Mix for 2005 and 2011

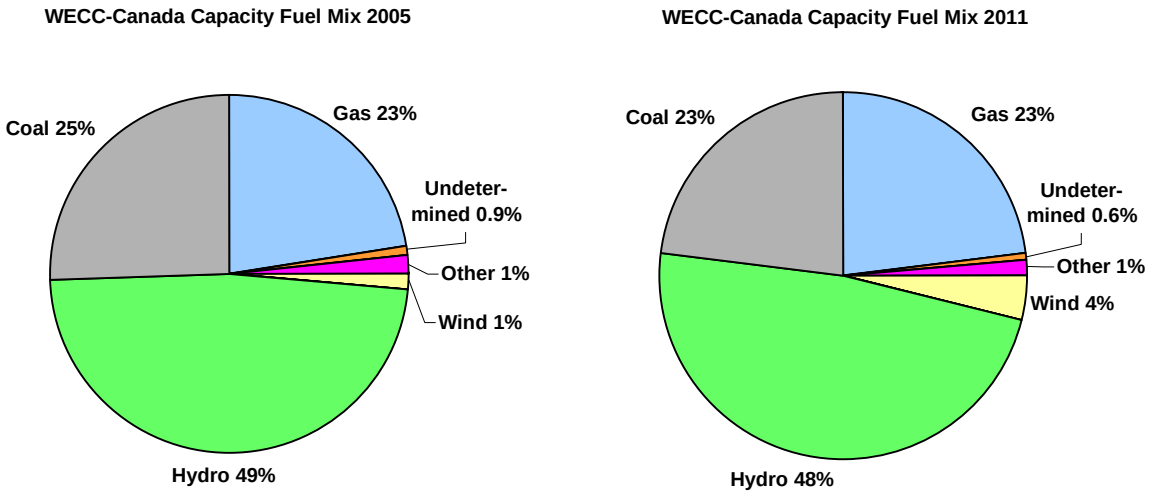
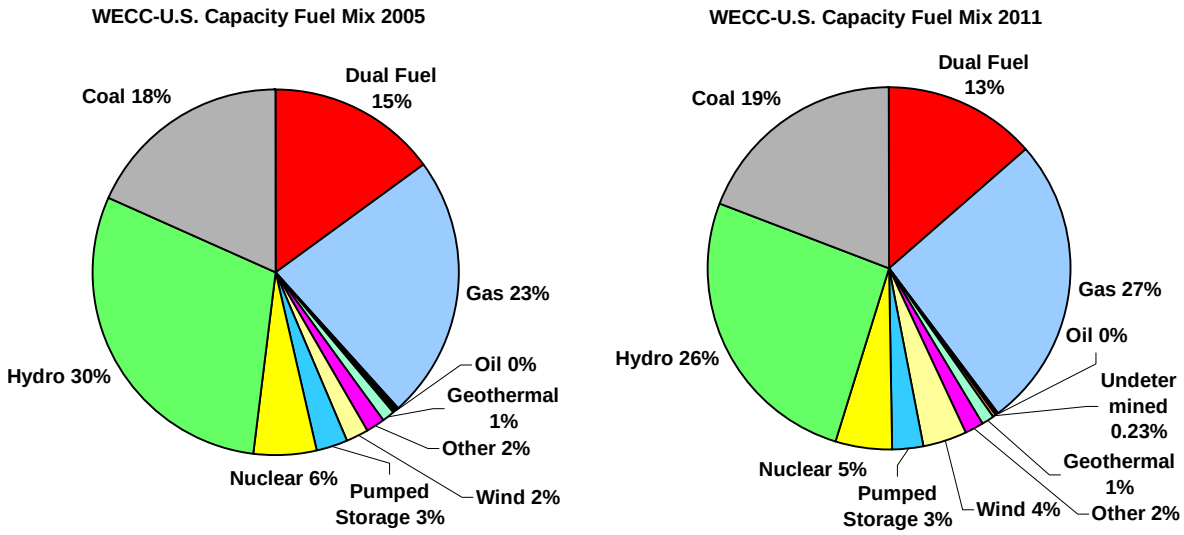


Figure 53: WECC-U.S. Capacity Fuel Mix for 2005 and 2011



Demand, Resource, and Transmission Projections

Table 3a: Estimated 2007 Summer Resources and Demands (MW) and Margins (%)

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted/ Energy-only/ Transmission-limited Resources (MW)	Available Capacity Margin W/O Uncommitted (%)	Potential Capacity Margin With Uncommitted (%)
United States					
ERCOT	62,072	70,384	6,836	11.8	19.6
FRCC	43,778	51,680	1,150	15.3	17.1
MRO	40,630	47,440	1,045	14.4	16.2
NPCC	59,582	71,950	2,635	17.2	20.1
New England	27,041	31,053	2,635	12.9	19.7
New York	32,541	40,897	0	20.4	20.4
RFC	189,900	221,980	9,422	14.5	17.9
SERC	187,982	223,103	35,000	15.7	27.2
Entergy	27,673	33,183	16,602	16.6	44.4
Gateway	17,839	25,924	2,576	31.2	37.4
Southern	49,131	56,394	6,947	12.9	22.4
TVA	33,578	38,023	4,131	11.7	20.3
VACAR	60,611	69,579	4,744	12.9	18.4
SPP	41,694	47,960	7,652	13.1	25.0
WECC	131,418	162,566	1,585	19.2	19.9
AZ-NM-SNV	28,753	35,778	95	19.6	19.8
CA-MX-US	56,079	64,830	173	13.5	13.7
NWPP-US	35,836	52,650	783	31.9	32.9
RMPA	11,506	12,752	534	9.8	13.4
Total-U.S.	757,056	897,063	65,325	15.6	21.3
Canada					
MRO	5,702	7,918	0	28.0	28.0
NPCC	51,395	67,362	52	23.7	23.8
Maritimes	3,117	6,250	52	50.1	50.5
Ontario	25,423	28,727	0	11.5	11.5
Québec	22,855	32,385	0	29.4	29.4
WECC	17,312	22,131	452	21.8	23.3
Total-Canada	74,409	97,411	504	23.6	24.0
Mexico					
WECC	2,065	2,355	86	12.3	15.4
Total-NERC	833,530	996,829	65,915	16.4	21.6

Table 3b: Estimated 2007/2008 Winter Resources and Demands (MW) and Margins (%)

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted/ Energy-only/ Transmission-limited Resources (MW)	Available Capacity Margin W/O Uncommitted (%)	Potential Capacity Margin With Uncommitted (%)
United States					
ERCOT	44,184	72,642	7,720	39.2	45.0
FRCC	45,905	56,021	1,190	18.1	19.8
MRO	33,717	45,078	1,045	25.2	26.9
NPCC	49,363	77,304	1,971	36.1	37.7
New England	22,580	34,254	1,971	34.1	37.7
New York	26,783	43,050	0	37.8	37.8
RFC	155,100	231,216	9,865	32.9	35.7
SERC	167,660	228,036	35,000	26.5	36.3
Entergy	22,772	35,654	16,602	36.1	56.4
Gateway	13,796	26,390	2,576	47.7	52.4
Southern	41,626	54,863	6,947	24.1	32.7
TVA	33,647	39,058	4,131	13.9	22.1
VACAR	55,820	72,163	4,744	22.6	27.4
SPP	29,973	48,421	8,062	38.1	46.9
WECC	107,500	155,499	2,191	30.9	31.8
AZ-NM-SNV	18,374	33,804	149	45.6	45.9
CA-MX-US	40,559	52,178	217	22.3	22.6
NWPP-US	39,995	55,872	1,266	28.4	30.0
RMPA	9,840	12,906	622	23.8	27.3
Total-U.S.	633,402	914,217	67,044	30.7	35.5
Canada					
MRO	7,073	8,918	0	20.7	20.7
NPCC	66,076	74,811	52	11.7	11.7
Maritimes	5,137	6,580	52	21.9	22.5
Ontario	25,370	28,634	0	11.4	11.4
Québec	35,569	39,597	0	10.2	10.2
WECC	20,970	22,686	454	7.6	9.4
Total-Canada	94,119	106,415	506	11.6	12.0
Mexico					
WECC	1,525	1,968	86	22.5	25.8
Total-NERC	729,046	1,022,600	67,636	28.7	33.1

Table 3c: Estimated 2011 Summer Resources and Demands (MW) and Margins (%)

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted/ Energy-only/ Transmission-limited Resources (MW)	Available Capacity Margin W/O Uncommitted (%)	Potential Capacity Margin With Uncommitted (%)
United States					
ERCOT	67,884	70,330	7,202	3.5	12.4
FRCC	48,318	57,222	1,150	15.6	17.2
MRO	44,000	48,572	5,045	9.4	17.9
NPCC	63,629	72,622	1,248	12.4	13.9
New England	29,571	32,273	1,248	8.4	11.8
New York	34,058	40,349	0	15.6	15.6
RFC	203,800	220,841	19,874	7.7	15.3
SERC	204,992	242,176	44,217	15.4	28.4
Entergy	29,776	34,084	18,102	12.6	42.9
Gateway	18,723	28,227	3,991	33.7	41.9
Southern	54,144	62,902	8,697	13.9	24.4
TVA	36,686	41,698	4,131	12.0	20.0
VACAR	65,663	75,265	9,296	12.8	22.3
SPP	44,410	51,615	7,652	14.0	25.1
WECC	144,065	162,207	9,366	11.2	16.0
AZ-NM-SNV	32,622	35,609	2,190	8.4	13.7
CA-MX-US	60,535	67,878	1,360	10.8	12.6
NWPP-US	39,197	52,625	3,423	25.5	30.1
RMPA	12,513	12,411	2,393	-0.8	15.5
Total-U.S.	821,098	925,585	95,754	11.3	19.6
Canada					
MRO	5,984	8,213	0	27.1	27.1
NPCC	54,328	72,036	121	24.6	24.7
Maritimes	3,308	6,364	121	48.0	49.0
Ontario	27,490	32,192	0	14.6	14.6
Québec	23,530	33,480	0	29.7	29.7
WECC	18,964	22,023	1,502	13.9	19.4
Total-Canada	79,276	102,272	1,623	22.5	23.7
Mexico					
WECC	2,467	2,355	822	-4.8	22.3
Total-NERC	902,841	1,030,212	98,199	12.4	20.0

Table 3d: Estimated 2011/2012 Winter Resources and Demands (MW) and Margins (%)

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted/ Energy-only/ Transmission-limited Resources (MW)	Available Capacity Margin W/O Uncommitted (%)	Potential Capacity Margin With Uncommitted (%)
United States					
ERCOT	48,115	72,785	7,880	33.9	40.4
FRCC	50,288	61,823	1,190	18.7	20.2
MRO	36,437	46,952	5,045	22.4	29.9
NPCC	51,929	77,746	713	33.2	33.8
New England	24,170	35,095	713	31.1	32.5
New York	27,759	42,651	0	34.9	34.9
RFC	165,200	230,017	19,083	28.2	33.7
SERC	179,682	244,461	44,217	26.5	37.8
Entergy	24,403	37,722	18,102	35.3	56.3
Gateway	14,621	28,703	3,991	49.1	55.3
Southern	45,699	60,752	8,697	24.8	34.2
TVA	35,277	40,306	4,131	12.5	20.6
VACAR	59,682	77,071	9,296	22.6	30.9
SPP	32,325	51,955	8,062	37.8	46.1
WECC	116,728	154,790	10,185	24.6	29.2
AZ-NM-SNV	20,577	34,147	2,192	39.7	43.4
CA-MX-US	43,734	51,061	1,368	14.3	16.6
NWPP-US	42,824	56,134	5,315	23.7	30.3
RMPA	10,646	12,783	2,635	16.7	31.0
Total-U.S.	680,704	940,529	96,375	27.6	34.4
Canada					
MRO	7,333	9,358	0	21.6	21.6
NPCC	68,263	79,068	150	13.7	13.8
Maritimes	5,394	6,700	150	19.5	21.3
Ontario	26,420	32,256	0	18.1	18.1
Québec	36,449	40,112	0	9.1	9.1
WECC	22,850	22,596	1,484	-1.1	5.1
Total-Canada	98,446	111,022	1,634	11.3	12.6
Mexico					
WECC	1,861	1,697	822	-9.7	26.1
Total-NERC	781,011	1,053,248	98,831	25.8	32.2

Definitions and Notes for Tables 3a, 3b, 3c, and 3d

Net Internal Demand — Projected total internal demand less interruptible demand and direct control demand-side management. The regions are not expected to reach their peak demand simultaneously. Demand served under liquidated damages contracts is included.

Net Capacity Resources — Net generating capacity resources (existing, under construction, or planned) considered available (net operable), deliverable, and committed to serve demand, plus the net of capacity purchases and sales.

Uncommitted Resources — Generating resources (existing, under construction, or planned) that are not counted towards capacity 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.

Potential Capacity Margin — The difference between total potential resources (the sum of net capacity resources and uncommitted 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.

Note 1: The ERCOT capacity margin without uncommitted capacity is less than the minimum reliability target of 11 percent. Inclusion of some uncommitted capacity and publicly announced new generation that does not currently have an interconnection agreement could bring capacity margins up to or above the minimum target level by 2011.

Note 2: It is not always possible to obtain SERC region totals by simply summing the subregions. Due to the diversity caused by geographic size and other factors, peaks do not occur simultaneously. This accounts for noncoincident demands and differences in reported resources, especially purchases and sales, across the subregions and the region.

Note 3: The sum of WECC-U.S. systems, Canada, and Mexico peak hour demands or planned capacity resources do not necessarily equal the coincident Western Interconnection total because of subregional and country peak demand diversity. Also, the WECC-U.S. area subregional net capacity resources numbers include utilization of seasonal demand diversity between the winter peaking northwest and the summer peaking southwest. To avoid double counting of resources, the WECC-U.S. net capacity resource totals do not include the diversity utilization.

Note 4: The WECC-U.S. systems uncommitted resources are not necessarily the sum of the U.S. subregion numbers. Subregion committed and uncommitted resources are for the month of maximum seasonal peak demand, which may differ from the month of maximum seasonal peak demand for the WECC-U.S. area. For the winter peak period, the NWPP-U.S. and AZ-NM-SNV subregions peak in

January, while the WECC-U.S. area and the remaining U.S. subregions peak in December. For the summer peak period, the CA-MX-U.S. subregion peaks in August, while the WECC-U.S. area and the remaining U.S. subregions peak in July. Hence, committed and uncommitted additions reported with August and January in-service dates might be reported for some subregions for a given year but not in the WECC-U.S. area until the following year.

Transmission Additions

More than 9,179 miles of new transmission (230 kV and above) are proposed for construction through 2010, with a total of 12,873 miles added over the 2006–2015 time frame. This represents a 6.1 percent increase in the total amount of installed transmission in North America over the assessment period. Table 4 provides a projection of planned increases in transmission circuit miles for 230 kV and above.

Table 4: Planned Transmission Circuit Miles – 230 kV and Above

	2005 Existing	2006-2010 Additions	2011-2015 Additions	2015 Total Installed
United States				
ERCOT	8,311	648	-	8,959
FRCC	6,998	350	127	7,475
MRO	15,912	1,382	272	17,566
NPCC	6,426	364	16	6,806
New England	2,493	273	16	2,782
New York	3,933	91	-	4,024
RFC	26,258	592	-	26,850
SERC	31,179	1,292	947	33,418
Entergy	5,037	151	268	5,456
Gateway	1,897	111	-	2,008
Southern	9,405	350	513	10,268
TVA	2,666	94	-	2,760
VACAR	12,174	586	166	12,926
SPP	9,955	14	21	9,990
WECC	58,751	3,063	1,821	63,635
AZ-NM-SNV	10,271	835	1,471	12,577
CA-MX-US	17,676	790	-	18,466
NWPP-US	24,883	704	350	25,937
RMPA	5,921	734	-	6,655
Total-U.S.	163,790	7,705	3,204	174,699
Canada				
MRO	6,730	303	65	7,098
NPCC	28,998	603	-	29,601
Maritimes	2,196	60	-	2,256
Ontario	11,137	95	-	11,232
Québec	15,665	448	-	16,113
WECC	10,979	416	233	11,628
Total-Canada	46,707	1,322	298	48,327
Mexico				
WECC	638	152	192	982
Total-NERC	211,135	9,179	3,694	224,008

DEFINITIONS, PEER REVIEW PROCESS, 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:

- Resource 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.

Under the heading of Adequacy, system operators can and should take "controlled" actions or procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include:

- Public appeals.
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5 percent).
- Interruptible demand — customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator or by action of the customer at the direct request of the system operator.
- Rotating blackouts — the term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, in effect rotating the outages among many sets of feeders.

Under the heading of Operating Reliability, are all other system disturbances that result in the unplanned and/or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as "cascading blackouts" — the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

What occurred in 1965 and again in 2003 in the northeast were uncontrolled cascading blackouts. What happened in the summer of 2000 in California, when supply was insufficient to meet all the demand, was a "rotating blackout" or controlled interruption of customer demand to maintain a balance with available supplies while maintaining the overall reliability of the interconnected system.

Peer Review Process

The RAS uses a three-phase approach in its peer reviews process during the preparation of reliability assessments. First, prior to the subcommittee meeting(s), each regional self-assessment is individually assigned to a subcommittee member (from another region) for an in depth, comprehensive review of the self-assessment. The results of that analysis are reviewed with the writer(s) of the respective self-assessment, and refinements/adjustments are made as necessary prior to the subcommittee meeting. Second, during the subcommittee meeting(s), each regional self-assessment is subjected to a group scrutiny and review by the entire subcommittee. Finally, at each meeting a region is selected on a rotating

basis to present a review of the assessment process used in their region following a broad set of questions aimed towards providing the subcommittee with a thorough understanding of that region's assessment procedures and practices.

About the Data Used in This Report

Detailed background data used in the preparation of this report is available in NERC's Electricity Supply & Demand (ES&D) database, 2005 edition (http://www.nerc.com/~esd/).

Most new generation additions over the next few years will be constructed by the merchant generation industry. NERC has contracted with Energy Ventures Analysis, Inc. (EVA) (http://www.evainc.com) to monitor and track the status of proposed new power plant projects as well as plant cancellations, delays, and retirements. In some cases, data available from EVA are used in this report to supplement data submitted by the NERC regions.

Abbreviations Used In This Report

AZ-NM-SNV	Arizona-New Mexico-Southern Nevada (Subregion of WECC)
CA-MX-US	California-Mexico (Subregion of WECC)
dc	Direct Current
DOE	U.S. Department of Energy
ECAR	East Central Area Reliability Coordination Agreement
EECP	Emergency Electric Curtailment Plan
ERCOT	Electric Reliability Council of Texas
FERC	U.S. Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GHG	Greenhouse Gas
GRSP	Generation Reserve Sharing Pool
GTA	Greater Toronto Area
GWh	Gigawatthours
ICAP	Installed Capacity
IESO	Independent Electric System Operator (in Ontario)
IPSI	Integrated Power System Plan
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kV	kilovolts (thousands of volts)
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LSE	Load-serving Entities
LTRA	Long-Term Reliability Assessment
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MEN	MAAC-ECAR-NPCC
MISO	Midwest Independent Transmission System Operator

MRO	Midwest Reliability Organization
MVA	Megavoltamperes
Mvar	Megavars
MW	Megawatts (millions of watts)
NERC	North American Electric Reliability Council
NIETC	National Interest Electric Transmission Corridor
NPCC	Northeast Power Coordinating Council
NWPP	Northwest Power Pool Area (subregion of WECC)
NYISO	New York Independent System Operator
OVEC	Ohio Valley Electric Corporation
PAR	Phase Angle Regulators
PJM	PJM Interconnection
PRB	Powder River Basin
PRSG	Planned Reserve Sharing Group
RAS	Reliability Assessment Subcommittee
RCC	Reliability Coordinating Committee
RFC	ReliabilityFirst Corporation
RFP	Request For Proposal
RMPA	Rocky Mountain Power Area (subregion of WECC)
RMR	Reliability Must Run
RRS	Reliability Review Subcommittee
RTO	Regional Transmission Organization
SCR	Special Case Resources
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
SPS	Special Protection System
THI	Temperature Humidity Index
TLR	Transmission Loading Relief
TVA	Tennessee Valley Authority
VACAR	Virginia and Carolinas (subregion of SERC)
WECC	Western Electricity Coordinating Council

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