NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2007 Long-Term Reliability Assessment

2007-2016

to ensure
the reliability of the
bulk power system

October 2007

116-390 Village Blvd., Princeton, NJ 08540
609.452.8060 | 609.452.9550 fax
www.nerc.com

Version 1.0 October 16, 2007
Version 1.1 October 25, 2007 (see Errata p. 237)

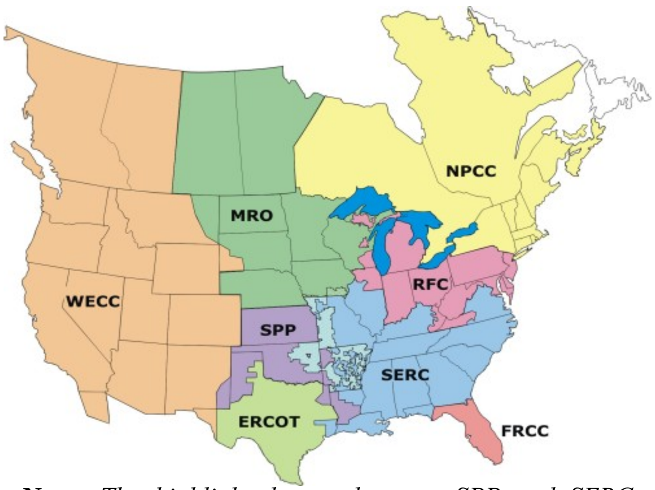
Current draft in bold

Table of Contents

NERC's Mission

The North American Electric Reliability Corporation's (NERC) mission is to ensure the bulk power system in North America is reliable. To achieve this objective, NERC develops and enforces reliability standards; monitors the bulk power system; assesses and reports on future adequacy; evaluates owners, operators, and users for reliability preparedness; and offers education and certification programs to industry personnel. NERC is a non-profit, self-regulatory organization that relies on the diverse and collective expertise of industry participants that form its various committees and sub-committees. It is subject to oversight by governmental authorities in Canada and the United States (U.S.)

NERC assesses and reports on the reliability and adequacy of the North American bulk power system divided into the eight regional areas as shown on the map below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada and a portion of Baja California, Mexico.



Note: *The highlighted area between SPP and SERC denotes overlapping regional area boundaries: For example, some load serving entities participate in one region and transmission owner/operators in another.*

ERCOT Electric Reliability Council of Texas, Inc.	**RFC** Reliability*First* Corp.
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corp.
MRO Midwest Reliability Organization	**SPP** Southwest Power Pool, Inc.
NPCC Northeast Power Coordinating Council	**WECC** Western Electricity Coordinating Council

As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce reliability standards with all U.S. owners, operators, and users of the bulk power system, and made compliance with those standards mandatory, as opposed to voluntary. NERC has similar authority in Ontario and New Brunswick, and is seeking to extend that authority to the other Canadian provinces. NERC will seek recognition in Mexico once the necessary legislation is adopted.

While the onset of mandatory and enforceable standards does not impact the preparation of this assessment, the significant efforts being made by users, owners, and operators of the bulk power system to comply with these standards are expected to significantly improve reliability.

Introduction

The *2007 Long-Term Reliability Assessment* report represents NERC's independent judgment of the reliability and adequacy of the bulk power system in North America for the next ten years.

NERC's primary roles in providing this assessment are to identify areas of concern regarding the reliability of the North American bulk power system, and to make recommendations for their remedy. This is the second such assessment prepared by NERC in its capacity as the U.S. Electric Reliability Organization.[1] NERC cannot order construction of additional generation or transmission or adopt enforceable standards having that effect, as that authority is explicitly withheld by Section 215 of the U.S. Energy Policy Act of 2005[2]. In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets.

The *2007 Long-Term Reliability Assessment* provides a high-level assessment of future resource adequacy, an overview of projected electricity demand growth and generation and transmission additions, an analysis of two scenarios that could affect future reliability, and regional self-assessments. This year's report also includes an in-depth discussion of long-term emerging issues and trends that, while not posing an immediate threat to reliability, will influence future bulk power system planning, development, and system analysis.

NERC's Annual Assessments

Assessment	Outlook	Published
Summer Assessment	Upcoming season	May
Long-Term Assessment	10 year	October
Winter Assessment	Upcoming season	November

Report Preparation

NERC prepared the *2007 Long-Term Reliability Assessment* with support from the Reliability Assessment Subcommittee (RAS) under the direction of the NERC Planning Committee (PC). The report is based on data and information submitted by each of the eight regional entities submitted in March 2007 and periodically updated throughout the process. Any other data sources consulted by NERC staff are identified in the report.

NERC uses a peer review process in preparing its reliability assessments taking full advantage of subject matter experts from across the industry. This process provides an essential check and balance ensuring the validity of the data and information provided by the regional entities. Each

[1] Section 39.11(b) of the U.S. FERC's regulations provide that: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[2] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf

regional self-assessment is individually assigned to subcommittee members from other regions for in-depth and comprehensive review. Reviewer comments are discussed with the regional entity representative and refinements/adjustments are made as necessary. Each regional self-assessment is then subjected to scrutiny and review by the entire subcommittee. This review ensures that each member of the subcommittee is confident that each regional self-assessment is accurate, thorough, and complete. The entire document, including the regional self-assessments, is subjected to review by the PC and the Member Representatives Committee (MRC) fully vetting all findings and conclusions. At the conclusion of this process, NERC management reviews the assessment results in detail before the report is submitted to the NERC Board of Trustees (BOT) for final approval.

To further increase the transparency of the process and conclusions of the assessment, NERC this year sponsored a public workshop designed to discuss preliminary findings with industry experts and participants, identify industry concerns that may have been missed, and solicit improvements for the reliability assessment process. Key suggestions from this workshop were reflected in the final report. The presentations and notes from the workshop are posted on the NERC Web site[3].

In this *2007 Long-Term Reliability Assessment*, the baseline calculations of electricity supply and internal demand projections are based on these assumptions:[4]

- NERC's projections are based on the regional forecasts submitted in March 2007. Any subsequent resource plan changes may not be fully represented.
- Average weather is assumed at the time of the peak in demand forecasts.
- Economic activity will occur as assumed in the demand forecasts.
- Generating and transmission equipment will perform at historical availability levels.
- Planned outages and additions/upgrades of generation and transmission will be completed as scheduled.
- Demand reductions expected from direct control load management and interruptible demand contracts will be effective, if and when they are needed.
- Other peak demand-side management and demand response programs are included in net internal demand forecasts.
- Electricity transfers between regions are contractually arranged and occur as projected.

[3] http://www.nerc.com/~filez/ltra_workshop.html

[4] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. Each regional demand projection, for example, is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the midpoint projections due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a long-run 50 percent probability that actual demand will be higher than the forecast midpoint and a long-run 50 percent probability that it will be lower.

For planning and analytical purposes, it is useful to have an estimate not only of the expected midpoint of possible future outcomes, but also of the distribution of probabilities around the projection. Accordingly, the Load Forecasting Working Group (LFWG) develops for each an upper and lower ten percent confidence band around the NERC regional demand and energy projections. This means there is a long-run 80 percent probability that future demand and energy will occur within these bands. Concurrently, there is a ten percent chance future outcomes could be less than the lower band and a ten percent chance future outcomes could be higher than the upper band.

The high and low bands around the demand forecasts are depicted in the charts at the end of each region's self assessment

Progress Since 2006

In its *2006 Long-Term Reliability Assessment*, NERC identified four "Key Findings" that could critically impact long-term reliability unless prompt actions are taken: declining capacity margins, lagging transmission construction, fuel supply and delivery issues (focusing on natural gas), and the aging industry workforce.

The magnitude of these issues necessitates complex solutions, the impacts of which may not be realized for several years. While some progress has been made (as summarized in the chart below), efforts to date have yet to substantially mitigate the risk of these issues to future reliability. Each of the four issues is therefore highlighted again in the 2007 report as a "key finding." A fifth finding is also highlighted in the next section regarding the *integration of wind, solar and nuclear resources*.

Progress on 2006 Findings

Finding 1: Electric capacity margins continue to decline — action needed to avoid shortage

Overall committed capacity margins improved by approximately two percent in the U.S. over the last year, but margins in some areas decreased. Several areas established forward capacity market, which will be relied upon to provide the necessary, new resources to maintain reliability.

Finding 2: Construction of new transmission is still slow and continues to face obstacles

Almost 2,000 miles of transmission were added to U.S. the bulk power system in the past year representing a little over one percent increase. Two draft DOE National Interest Electric Transmission Corridors were identified.

Finding 3: Fuel supply and its delivery to electric generation are vital to maintaining reliability

Organizations in Florida, California and the ISO New England – all representing areas with high dependence on natural gas fuel -- performed studies identifying specific concerns and courses of action to mitigate the risks of supply and delivery interruptions. In ISO New England, 2,300 MW of single-fuel, gas-fired capacity was converted to dual-fuel capability.

Finding 4: Aging workforce presents challenges to future reliability

Industry action is urgently needed to meet the expected 25 percent increase in demand for engineering professionals by 2015. Enhanced recruitment and outreach efforts through consortia, partnerships with local colleges, and increasing R&D support of university programs are vital for developing future industry talent.

2007 Key Findings

NERC's key findings along with the recommendations[5] and conclusions are based on broad observations derived from data submitted as part of the long-term reliability assessment, study of industry emerging industry issues, NERC staff assessment and stakeholder comments. The *Adequacy Assessment*, *Scenario Analysis* and *2007 Long-Term Emerging Issues* sections include additional significant findings.

There are significant uncertainties in the six-ten year horizon of this report, driven by resource acquisition and regulatory uncertainties. Understanding the influence of these uncertainties on reliability is vital to increase the assessment of bulk power reliability.

[5] The "Recommendations" for each of the key findings 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.

1. Long-term Capacity Margins are Still Inadequate

Though the gap has narrowed in many areas due to commitments to new supply-side and demand-side resources, projected increases in peak demands continue to exceed projected committed resources beyond the first few years of the ten-year planning horizon. Newly created forward capacity markets are being relied upon to provide needed new resources in most areas with structured markets and show promise. Areas with traditional "obligation to serve" arrangements are expected to develop sufficient resources to meet their regulatory commitments.

Based on the data submitted to NERC, peak demand for electricity in the U.S. occurs in summer, and forecast to increase by over 135,000 MW or 17.7 percent in the next ten years — nearly the current peak demand of the entire Western Interconnection. Committed resources are projected to increase by 77,000 MW or 8.4 percent. With uncommitted resources, the increase expands to 123,000 MW or 12.7 percent.

Peak demand for electricity in Canada (which occurs in winter) is forecast to increase by over 6,000 MW or 6.4 percent in the next ten years — approximately enough energy to power 4.5 million homes on an average day. On the reverse side, committed resources are projected to increase by 11,000 MW or over ten percent. With uncommitted resources, that increases to slightly less than 14,000 MW or 12.5 percent.

While these figures indicate some improvement in capacity margins over the 2006 forecasts, certain areas will still need additional supply-side or demand-side resources in the near-term to ensure adequate margins. Areas of the most concern include WECC-Canada, California, Rocky Mountain States, New England, Texas, Southwest and the Midwest. The outlook improves somewhat when uncommitted resources — those resources still too early in the planning process to commit to providing energy — are included. Even with these uncommitted resources included, some areas remain a concern.

Additional resources, not included in the data submitted to NERC due to their uncertain nature, are being developed. For example:

- ISO New England and PJM (the Pennsylvania-New Jersey-Maryland

Committed & Uncommitted Capacity Resources

Committed Capacity Resources

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

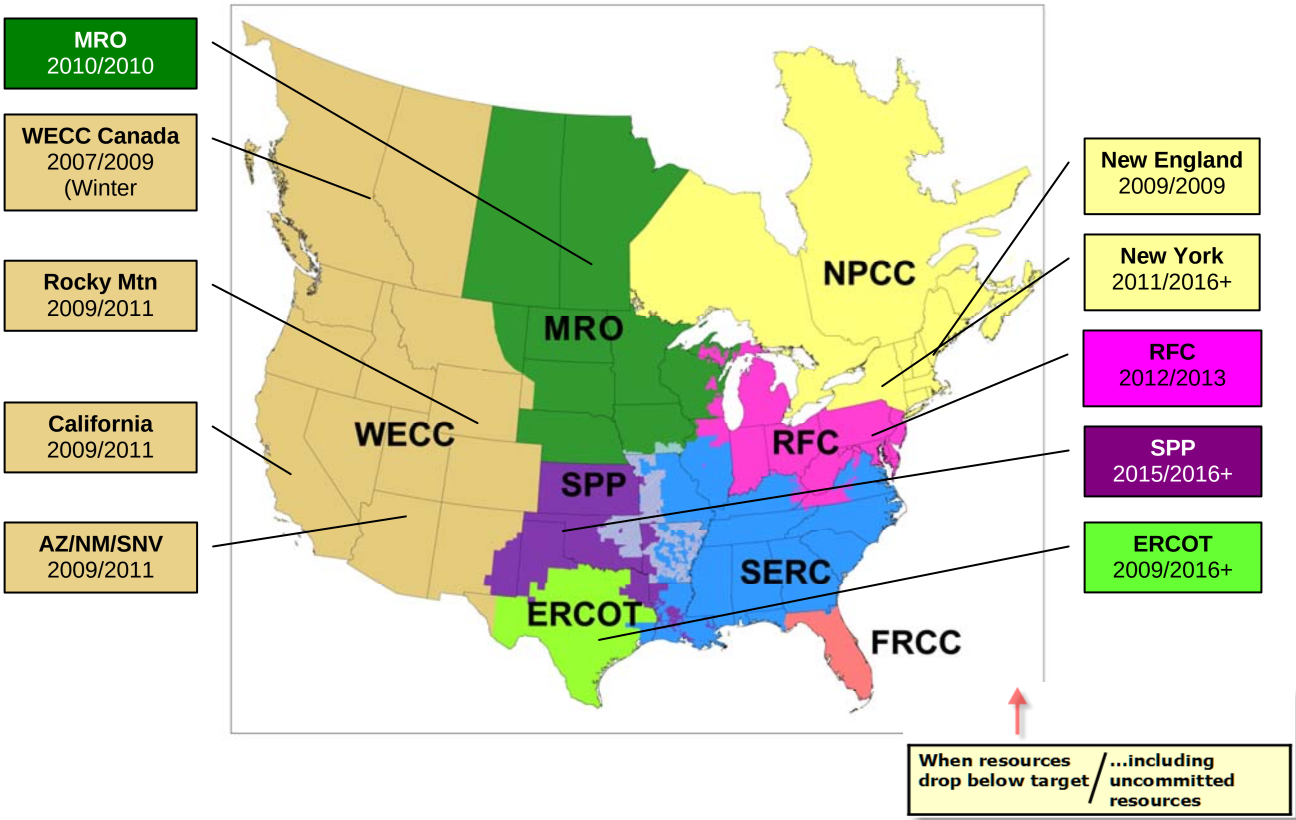
Uncommitted Capacity Resources

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.

system operator) have proactively begun integrating long-term resource planning into their market structures through new "forward capacity markets." The mechanisms supporting these markets are in place and look promising for the future.

- In all or portions of other areas such as WECC, MRO and FRCC, there is a state-mandated "obligation to serve" that may either be a back-stop to organized markets or the primary approach to support construction of new resources. Though there is insufficient commitment to include these potential resources in this assessment's calculations, these areas have historically met their capacity margins requirements.



The map above identifies the years when a region/subregion drops below target capacity margin levels required to meet summer peak (unless noted as winter) including both committed and uncommitted resources Those region/subregions not identified are not projected in the next ten years to drop below their target margin levels.

Note: *The highlighted area between SPP and SERC denotes overlapping regional boundaries*

A major driver of the uncertain or inadequate capacity margins is the industry's relatively recent shorter-term approach to resource planning and acquisition, relying heavily on unspecified, undeveloped, and/or uncommitted resources to meet projected demand. This trend has been made possible by shorter plant construction times — especially in the case of natural gas plants that can be constructed in as little as 18 months. Shorter term commitments are generally more attractive to investors and load-serving entities alike, as they offer more certainty on potential revenues, demand trends, and the regulatory climate before investments are made.

However, short-term planning can't preclude long-range strategies for modernization and expansion of the bulk power system. A focus solely on short-term planning does not result in the efficient design and construction of the grid of the future, and does not provide the long-range visibility and certainty needed regarding reliability. Dependence on short-term natural gas generation to solve reliability needs overlooks the need to integrate other necessary resources such as transmission, commercial and industrial development, and demand-side program planning. For example, siting transmission lines to transport power from the new generation typically involves a longer process, especially when new rights-of-way are required through heavily populated areas.

A recent development that could adversely affect future capacity margins is the EPA's July 2007 suspension[6] of its Phase II, Section 316(b) of the Clean Water Act[7] rules regarding cooling water intake structures and thermal discharges of once-through cooled power plants. While plant specific outcomes will vary, retrofitting existing power plants with cooling towers can reduce the capacity of those plants, which will exacerbate the supply concerns identified in the this assessment. In some cases, retrofits may prove so costly that plants are retired earlier than projected, with the consequent loss of the plant's entire capacity. At a time when additional electricity generating resources are needed, the loss of existing generating capacity would undermine U.S. efforts to meet the growing demand for electricity.

Recommendations and Conclusions

- Formal markets without traditional "obligation to serve" requirements must be proactive in integrating long-term resource planning into their market structures to ensure needed resources are developed.
- Regulators, planning authorities, and transmission planners should support the re-introduction of a planning model that integrates generation and transmission planning to ensure coordinated development of the bulk power system.
- State, provincial, and federal regulators need to encourage investment in long-term bulk power system projects.
- Regulators, planning authorities, and transmission planners should enhance long-term transmission planning analyses to support long-term resource needs.

NERC Actions

- NERC will improve its definition of uncommitted resources and various gradations of certainty for future resources to improve its assessment of long-term capacity margins.

6 http://www.epa.gov/waterscience/316b/phase2/

7 U.S. Clean Water Act, page 169, http://www.epa.gov/region5/water/pdf/ecwa_t3.pdf

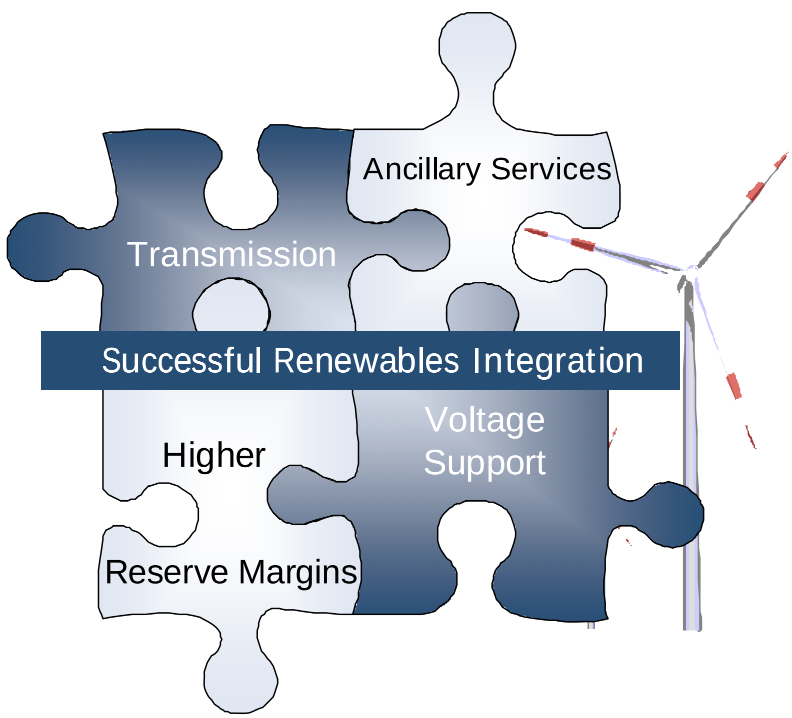
2. Integration of Wind, Solar, and Nuclear Resources Require Special Considerations in Planning, Design, and Operation

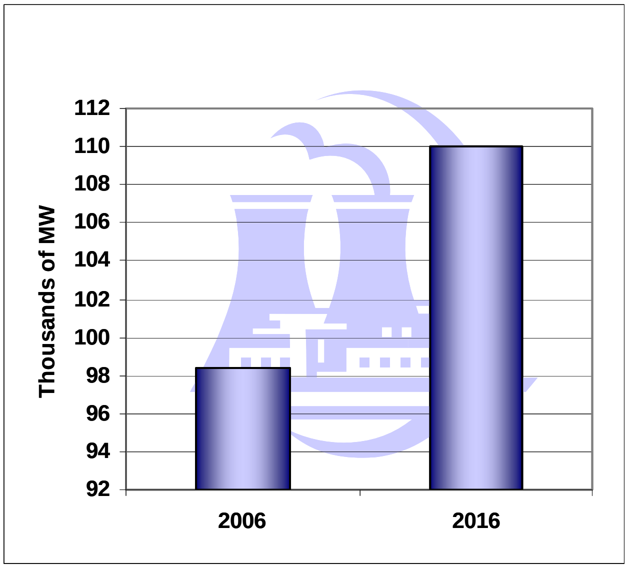
Wind, solar, and nuclear resources have unique characteristics that must be accommodated in the planning, design and operation of the bulk power system. Transmission infrastructure must be developed to reliably integrate these resources, while maximizing their potential to meet resource requirements and reduce greenhouse gas emissions.

Wind and Solar

Regulatory trends, coupled with the increasing viability of renewable resources, have resulted in greater planned use of non-carbon emitting generators. With the potential for federal CO_2 legislation increasing, the trend toward renewable resources is expected to continue and increase.

Much new emphasis is being placed on wind and solar resources in long-term resource planning, especially in ERCOT, SPP, WECC, and MRO where some states have mandated Renewable Portfolio Standards. This proposed level of commitment to renewables offers many benefits (new generation resources, fuel diversification, greenhouse gas reductions), as well as challenges. The unique characteristics and attributes of renewables require special considerations for planning. For example, they are often remotely located, requiring significant transmission links often over challenging terrain. Wind and solar resource variability requires ancillary services such as voltage support, frequency control, increased base-load unit dispatch flexibility, and spinning reserves. In addition, many times their available generating capacity at time of peak is significantly less than their nameplate capacity varying with location. Those entities responsible for bulk power system reliability must take these unique characteristics and attributes into account to ensure wind and solar are reliably integrated into the system.





The NRC predicts to receive applications for 32 new nuclear units by 2009 – proposed as 12,000 additional MW coming online in 2015-2016.

Nuclear

A total of 12,000 MW of new-build nuclear capacity[8] is proposed in 2015–2016. The design specifications for some of these units are large (over 1,600 MW). Significant investment in transmission is vital to support these large units — including their larger safety loads following reactor trips -- and ensure that they are reliably integrated into the system. Because of the long-lead times for major transmission development and siting, and the considerably shorter lead-time[9] for new nuclear units, transmission must be initiated sufficiently far in advance to ensure that the transmission system will be ready to accommodate these units when they are licensed for operation.

Recommendations and Conclusions

- Mandates for aggressive RPS must be accompanied by active support for the development of, and investment in, the transmission infrastructure required to reliably integrate those resources into the bulk power system.

NERC Actions

- NERC will evaluate the operational requirements to reliably integrate intermittent resources into the bulk power system and provide recommendations for draft standards as necessary.
- NERC will develop a consistent approach to rate intermittent resources, such as wind and solar, according to their available capacity at time of system peak.
- NERC will monitor the integration of new nuclear generation to ensure the transmission resources needed to reliably integrate proposed new units into the bulk power system are available, and the coordinated development of needed transmission reinforcements with transmission planners and planning coordinators.

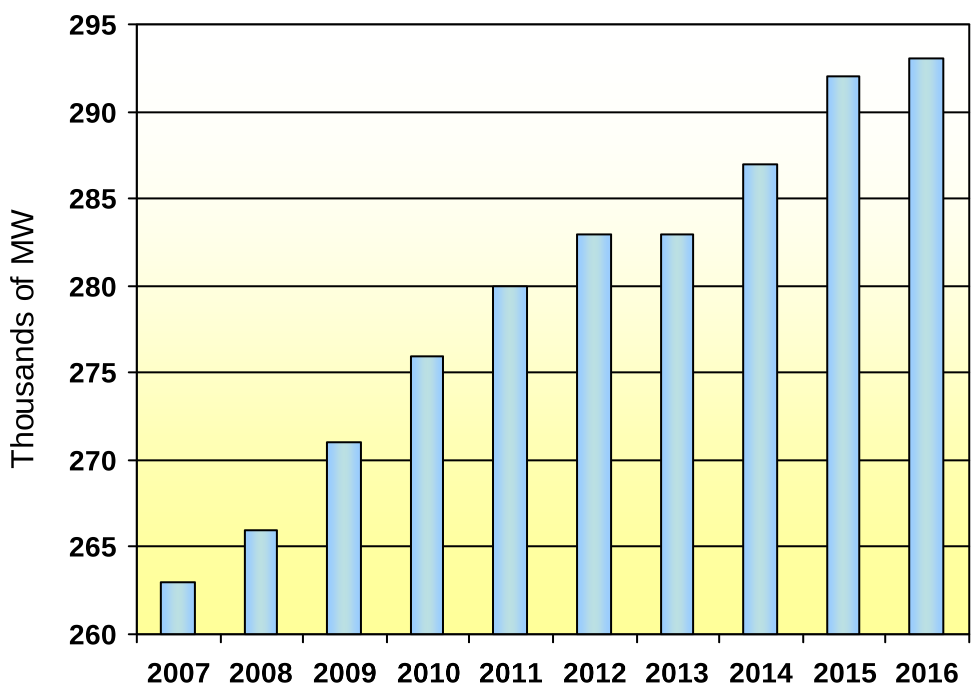
More information on the integration of wind, solar and nuclear resources can be found in the *Scenario Analysis* section.

[8] ERCOT: 6,176 MW, FRCC: 1,125 MW and SERC: 4,320MW
[9] Recent NRC Workshop: Current expectations are that it may take 78 months to complete nuclear plant construction.

3. High Reliance on Natural Gas in Some Areas of the U.S. Must Be Properly Managed to Reduce the Risk of Supply & Delivery Interruptions

Continued high levels of dependence on natural gas for electricity generation in Florida, Texas, the Northeast, and Southern California have increased the bulk power system's exposure to interruptions in fuel supply and delivery. Efforts to address this dependence must be continued and actively expanded to avoid risks to future resource adequacy.

Nineteen percent of the U.S. electric industry's generation capacity is powered by natural gas. That is expected to increase to 22 percent[10] over the next ten years. In Texas, this dependency is much higher, projected to grow close to 58 percent by 2016. Florida, California-Arizona-Southern Nevada, and the Northeastern portion of the U.S., are also highly dependent on natural gas as a fuel for electricity generation, with growing reliance in the Southeastern part of the U.S. along with the Southwest Power Pool, disruptions in the supply or delivery of natural gas could have a significant impact on the availability of electricity. Mitigation measures being implemented in some areas include: increased gas storage, alternate pipelines, expanded dual-fuel capability, fuel-conservation dispatching, and increased coordination with gas pipeline operators. These efforts must be continued and actively expanded to ensure future resource adequacy in the areas of highest dependence.

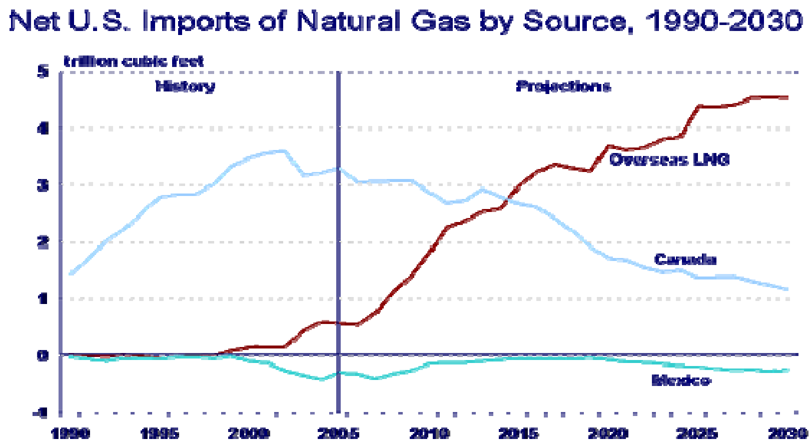


Natural gas is expected to fuel 22% of electricity produced in the U.S. by 2016.

Natural gas has become the "fuel of choice" for new-build generation as gas-fired plants are typically easy to construct, require little lead time, emit less CO_2, and are generally cheaper to construct than their coal and oil counterparts. Certain states have placed a moratorium on building new coal plants, citing environmental and emissions concerns as justification. These

[10] Energy Information Administration, 2007 Annual Energy Outlook, http://www.eia.doe.gov/oiaf/aeo/pdf/trend_3.pdf

trends are expected to continue over the next several years, further increasing the number of new-build natural gas plants in areas with already high dependence.



Canadian natural gas imports into the U.S. are expected to level off and decline overall as early as 2010 due to increasing demand in Canada.[11,12] This will leave a gap in available supply amid growing demand from home heating and new agricultural/industrial processes (such as ethanol production). This gap is expected to be filled by new supplies of Liquefied Natural Gas (LNG) from overseas, which will require siting and construction of LNG Terminals throughout North America. However, this terminal infrastructure is facing delays in most locations where it has been proposed. Importing LNG from abroad opens the U.S. fuel supply to the global market and all of the economic and political risks associated with it, such as those that have faced global oil markets. It also presents risks to the supply chain, such as international weather events that could delay shipments for weeks.

Long-term planning of natural gas resources is based on firm contracts for fuel transportation, in that firm contracts are required to trigger the government approvals needed to construct new pipelines. Current trends in contracting fuel supply have led to a high percentage of limited or release-firm contracts that enable generators to reduce costs, but result in minimal contractual rights to pipeline and storage capacity in the event of high demand. This contracting approach hampers the development of necessary supply and delivery infrastructure such as pipelines.

Significant progress toward addressing these concerns has been made since 2006, including exemplary research into the issue and the development of plans to solve it in Florida and the Western U.S. However, little has been accomplished in terms of new pipeline construction, LNG Terminal construction, or changing current policies. Some states, such as California and Florida, have not supported diversification to other fossil fuels, such as coal, with a number of announced plants disapproved. Sufficient mitigating strategies, such as storage, firm contracting, alternate pipelines, dual-fuel capability, nearby plants using other fuels, or additional transmission lines from other regions, must be considered. It is vital that infrastructure investments be made to increase the certainty of supply and delivery, and manage the risks associated with high dependency on a single fuel.

[11] Energy Information Administration, 2007 Annual Energy Outlook, http://www.eia.doe.gov/oiaf/aeo/pdf/trend_4.pdf
[12] American Gas Foundation, "The Energy Policy Act of 2005 and its Impact on the U.S. Natural Gas Supply/Demand Imbalance," January 2007, http://www.gasfoundation.org/ResearchStudies/AGF_EnergyPolicyStudy_Complete.pdf

Recommendations and Conclusions

- Resource planners in areas with high dependence on natural gas for electricity generation should take into account the potential for gas supply or delivery interruptions in their overall assessments of supply adequacy.
- Owners and operators of gas-fired generation should work together with resource planners on strategies to mitigate the potential impacts of gas supply or delivery interruptions during periods of high gas demand for other uses.
- Resource planners should work together with regulators to enable fuel diversification where high dependence on natural gas presents risks to the adequacy of electricity supply.
- Obstacles to developing new gas supply and delivery, including construction of LNG terminal facilities, must be addressed and resolved by government officials.

NERC Actions

- NERC will continue to identify and study fuel supply and transportation interruption scenarios that could adversely impact electric system reliability.

More information on the ramifications of natural gas dependency is provided in the *Scenario Analysis* section.

4. Transmission Situation Improves, but More Still Required

Several key transmission projects were completed and more transmission additions are proposed than reported in last year's assessment. Significant investment in transmission is still required in many areas of North America as projected transmission additions lag behind demand growth and new resource additions in most areas.

The total number of transmission miles is projected to increase by 8.8 percent (14,500 circuit miles) in the U.S. and 4.8 percent (2,250 circuit miles) in Canada over the next ten years. This is more than a 30 percent increase in proposed transmission miles since last year's assessment, which is a significant improvement. Looking at the next five years, the pace of proposed transmission projects in the U.S. appears to be accelerating, as projects will now be completed sooner than originally scheduled.

Appendix I includes examples of potentially significant transmission additions, most above 200 kV, which are expected to improve reliability and/or system efficiencies. The projects were identified by the NERC regional areas as vital transmission links/options, important for regional reliability during and beyond 2007–2016. Details on these and other transmission facility additions can be found in the 2007 EIA-411 submittals made to the U.S. Department of Energy by transmission owners and operators.

Though investment is increasing in some areas, lagging investment in transmission resources has been an ongoing concern for a number of years. More investment is required, as each peak season puts more and more strain on the transmission system, especially in constrained areas such as the Northeast, California and southwestern U.S., as well as parts of Ontario, Canada.

Table 1: Planned Transmission Circuit Miles
230 kV and Above

	2006 Existing	2007-2011 Additions	2012-2016 Additions	2016 Total Installed
United States				
ERCOT	8,515	874	242	9,631
FRCC	7,171	297	81	7,549
MRO	16,110	1,811	78	17,999
NPCC	6,191	339	16	6,546
New England	2,525	264	16	2,805
New York	3,666	75	-	3,741
RFC	26,878	441	-	27,320
SERC	32,324	1,677	573	34,574
Central	3,243	166	-	3,409
Delta	5,036	341	74	5,451
Gateway	1,952	57	-	2,009
Southeastern	9,581	415	473	10,469
VACAR	12,512	698	26	13,236
SPP	7,610	1,111	21	8,742
WECC	58,681	4,406	2,540	65,627
AZ-NM-SNV	10,300	1,231	946	12,477
CA-MX-US	17,682	1,522	-	19,204
NWPP-US	24,778	721	741	26,240
RMPA	5,921	932	853	7,706
Total-U.S.	163,480	10,956	3,551	177,988
Canada				
MRO	6,710	201	189	7,100
NPCC	29,252	630	402	30,284
Maritimes	2,196	60	-	2,256
Ontario	11,312	201	220	11,733
Québec	15,744	369	182	16,295
WECC	10,688	668	153	11,509
Total-Canada	46,650	1,499	744	48,893
Mexico				
WECC	674	152	192	1,018
Total-NERC	210,804	12,607	4,487	227,899

Positive steps are being taken in some states and provinces to expedite certain key projects, and the U.S. federal government will have back-stop authority through the DOE National Interest Electric Transmission Corridors (NIETC). But this is not enough.

The process of siting new transmission continues to be difficult and expensive due to local opposition, environmental concerns, and increasing legal battles, especially when lines are planned to cross state borders. Negotiations still delay and, in some cases, stop important projects from being built.

A recent NERC survey[13] of industry professionals ranked aging infrastructure and limited new construction as the **number one challenge to reliability** — both in likelihood of occurrence and potential severity.

Continued and increasing cooperation of all industry stakeholders is required to deliver the transmission additions needed for reliability, as these two examples convey:

- Phase Angle Regulators (PARs) intended to resolve loop flow issues occurring through the Canadian system (Ontario) have been in place since the beginning of 2006, but they are still not being actively used to manage loop flows due to protracted negotiations among the parties.
- The proposed Palo Verde-Devers #2 transmission line between Arizona and southern California has been recently halted due to state-level concerns.

Recommendations and Conclusions

- State, provincial, and federal government agencies need to factor the impact on inter-state and international bulk power system reliability into their evaluations, working together to remove obstacles, accelerate siting, and approve permits for transmission line construction.
- Customer education and outreach are needed should be fostered by the electric power industry to improve the general public's understanding of the issues and trade-offs around new transmission lines, and how new lines that increase reliability of the overall grid also benefit them.
- The agreement for the operation of the Michigan — Ontario PARs should be finalized.

NERC Actions

- NERC will continue to support the DOE NIETC effort, which is critical to improving reliability.

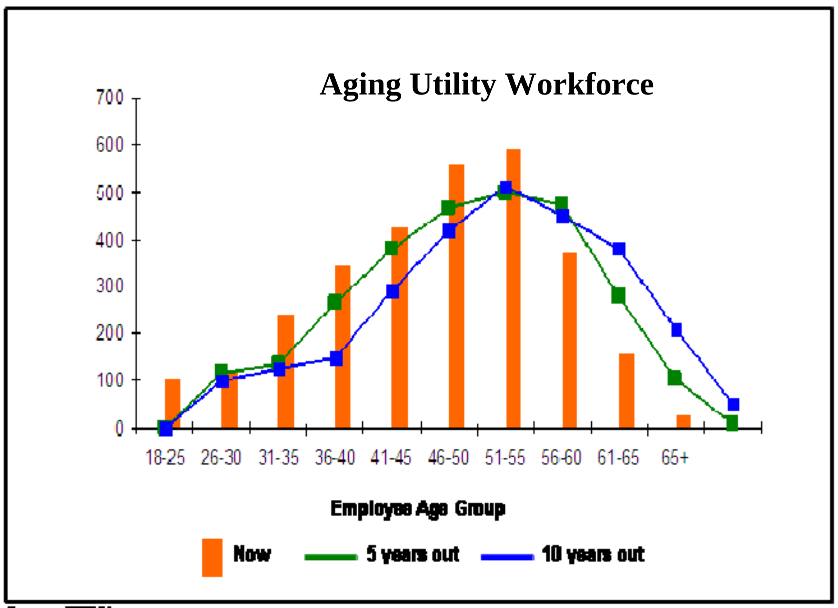
[13] ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/Reliability_Issue_Survey_Final_Report.pdf

5. Aging Workforce Still a Growing Challenge

The loss of industry workers and their years of accumulated expertise due to retirements is a serious threat to the bulk power system reliability, exacerbated by the lack of new recruits entering the field.

The capacity of the bulk power system is nearing its limits. New construction and rejuvenation of the bulk power system is required, using a variety of new technologies. This will require a substantial increase in the workforce. Yet the industry is dealing with a shrinking workforce, for reasons that include:

- Demographics (baby boomers[14] reaching retirement age[15], reduced birthrate, and — in the U.S. — lower immigration).
- Utility cost-cutting of recent years resulted in more early retirements of engineers, supervisors and line-workers.[16,17]
- Cost-cutting also drove utilities to outsource activities traditionally performed by in-house staff leading to the loss of in-house expertise.
- Reduced "head-room" in the electric industry (at manufacturers, vendors and institutes as well as utilities). New bulk power system construction slowed down due to the desire to avoid the economic risks of new construction, and to maximize the value of existing assets. This in turn decreased demand for new hires.



Source: KEMA

The industry workforce is aging in the U.S. By 2010, one in three U.S. workers will be age 50 or older (see graph). Meanwhile, the demand for workers is increasing. In 2015, a 25 percent increase in demand for industry workers is anticipated.

Exacerbating the problem of a declining workforce is a simultaneous decline in the number of potential recruits from colleges and universities, as well as vocational schools. During the past two decades, the reduced demand for industry workers has led to a decrease in vocational training and university-sponsored electric power programs Further to this point is the decline in the number of college professors able to teach power system engineering and related subjects.

---

[14] Wikipedia: Sometimes called "Baby-Boomers" the term is commonly applied to people with birth years after World War II (WW II) and before the Vietnam War, thus possibly comprising more than one generation.

[15] Ray, Dennis and Bill Snyder. *Strategies to Address the Problem of Exiting Expertise in the Electric Power Industry*. Proceedings of the 39th Annual Hawaii International Conference on System Sciences. January 2006.

[16] DOE Report: *Workforce Trends in the Electric Utility Industry*, required by Section 1101 of the Energy Policy Act of 2005

[17] Deloitte Canada: *Managing Talent Flow: 2006 Energy and Resources, Talent Pulse Survey Report*

Many organizations have recognized this challenge and are proactively beginning to support specific programs around North America.[18]

In coordination with the National Science Foundation (NSF), and co-sponsored by Power Systems Engineering Research Center (PSERC), the Institute of Electrical and Electronics Engineers —Power Engineering Society (IEEE-PES) and NERC, a workshop focused on creating an industry action plan, will be held later this year. This plan will act as a roadmap for future industry cooperation to tackle this reliability challenge.

NERC is also coordinating the efforts of various industry participants, the Idaho National Lab and the Pacific Northwest National Lab in developing the North American Grid Center of Excellence, which will be an enhancement for existing operator/dispatcher simulators. This enhancement will greatly improve the ability to transfer knowledge from the aging workforce to the incoming workforce. It will also be valuable in validating planning models and event reconstruction and analysis, and is consistent with recommendations in the final report of the U.S. — Canada Power System Outage Task Force on the August 14, 2003 blackout.

In addition, the Energy Policy Act of 2005, Title XI, Section 1101(c), Traineeship Grants for Skilled Technical Personnel, states that the Secretary of Energy, in consultation with the Secretary of Labor, may establish programs in the appropriate offices of the Department of Energy under which the secretary provides grants to enhance training for any workforce category for which a shortage is identified or predicted.[19]

Recommendations and Conclusions

In addition to the solutions above, many already in progress, the industry must accelerate the cultivation of new engineering talent to keep pace with its increasing reliability challenges. Specific recommendations include:

- University-level strategic research in power systems engineering must be supported, and funded, to strengthen programs that attract world-class faculty, and train world-class engineers.
- Industry participants should aggressively recruit and retain talent.
- The Secretary of Energy, working with Congress, should pursue the appropriation of funding support for the North American Grid Center of Excellence[20].

NERC Actions

- NERC will continue to support industry action and measure progress.

---

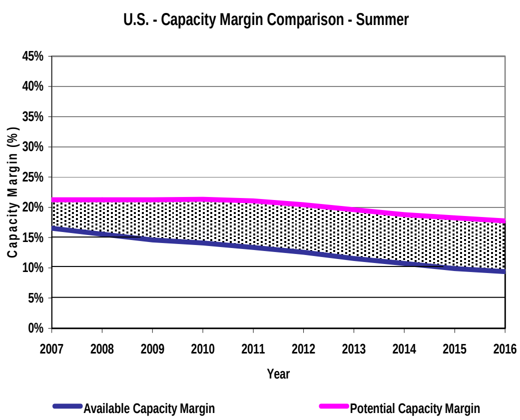
[18] ftp://www.nerc.com/pub/sys/all_updl/rap/audits/PEF_BA-TOP_ReadinessEvaluationRpt.pdf
[19] ftp://www.nerc.com/pub/sys/all_updl/docs/legislation/HR6(as-passed-by-House-and-Senate).pdf
[20] Energy Policy Act of 2005, Title XI, “Personnel and Training,” Section 1101(c), Workforce Trends and Traineeship Grants ftp://www.nerc.com/pub/sys/all_updl/docs/legislation/HR6(as-passed-by-House-and-Senate).pdf

Reliability Assessment

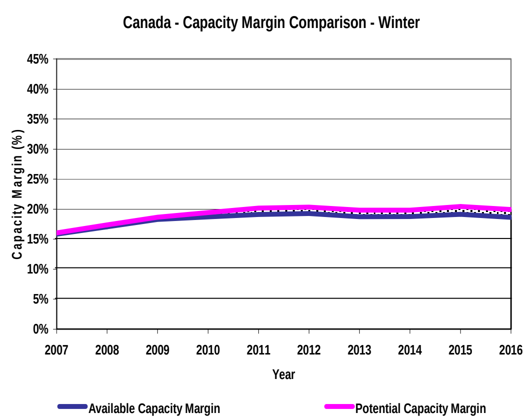
DEMAND AND RESOURCE PROJECTIONS

The peak demand projections shown in this report's tables and charts represent an aggregate of weather-normalized regional projections. In some cases, these regional aggregations do not take into account the regional diversity of among the various regional participants' peak demands, which, depending on the geographical size, could significantly influence the reserve margin comparisons. However, in other cases, as regions can be wide-spread, resources would not be deliverable, and sub-regional analysis is more meaningful.

The Load Forecasting Working Group (LFWG) develops bandwidths around the aggregate U.S. and Canadian demand projections to account for uncertainties inherent in demand forecasting (see the *Reliability Concepts Used in this Report*). This internal demand growth equates to a ten-year compound annual peak demand growth rate in the U.S. for 2007–2016 of 1.5 percent in the summer and 1.5 percent in the winter. In Canada, the ten-year compound annual peak demand growth rate is 0.7 percent in the summer and 0.8 percent in the winter. The average annual growth in the "high" and "low" band U.S. summer peak demands are 2.5 percent and 0.6 percent, and in Canada winter peak demands are 1.5 percent and -0.1 percent, respectively. Year-to-year demand growth rates can vary due to variations in economic conditions and weather. Also, actual demands reported herein are not corrected for weather or other conditions that deviate from the forecast assumptions. In comparison, the U.S. Energy Information Administration's (EIA) internal peak demand forecast ten-year compound annual growth rate is 1.7 percent for the summer and 1.5 percent for the winter during 2007–2016[21] for the U.S. EIA's analysis does not include Canada.



U.S. capacity margins decline throughout ten-year period.

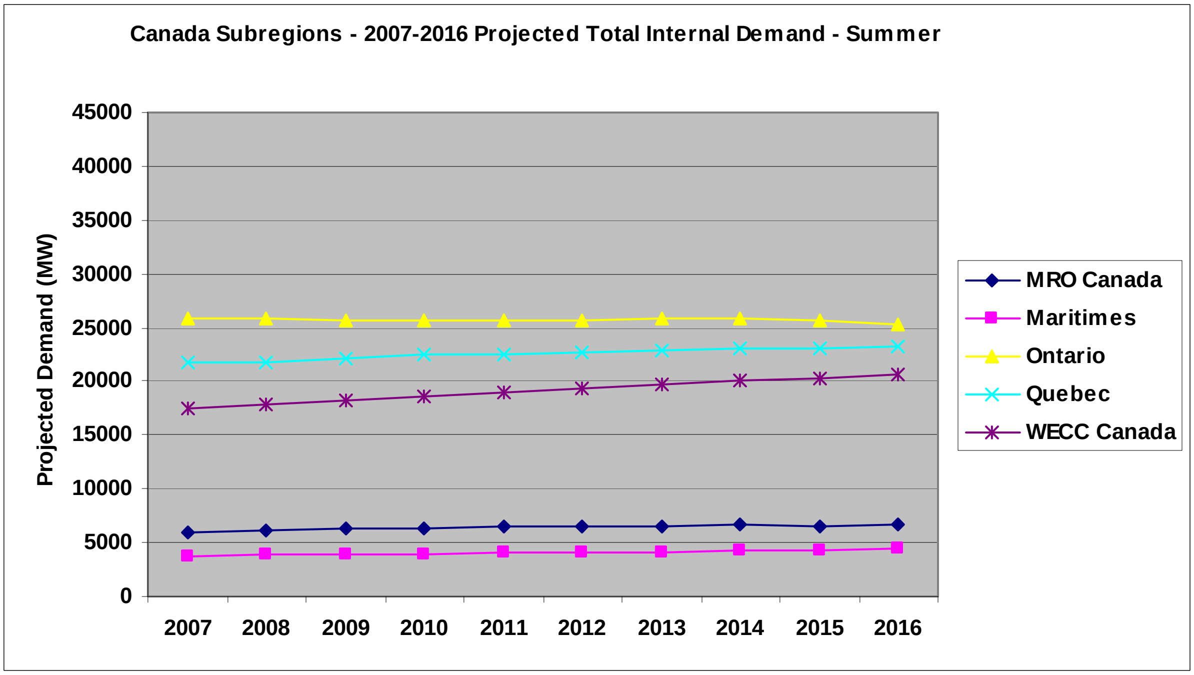


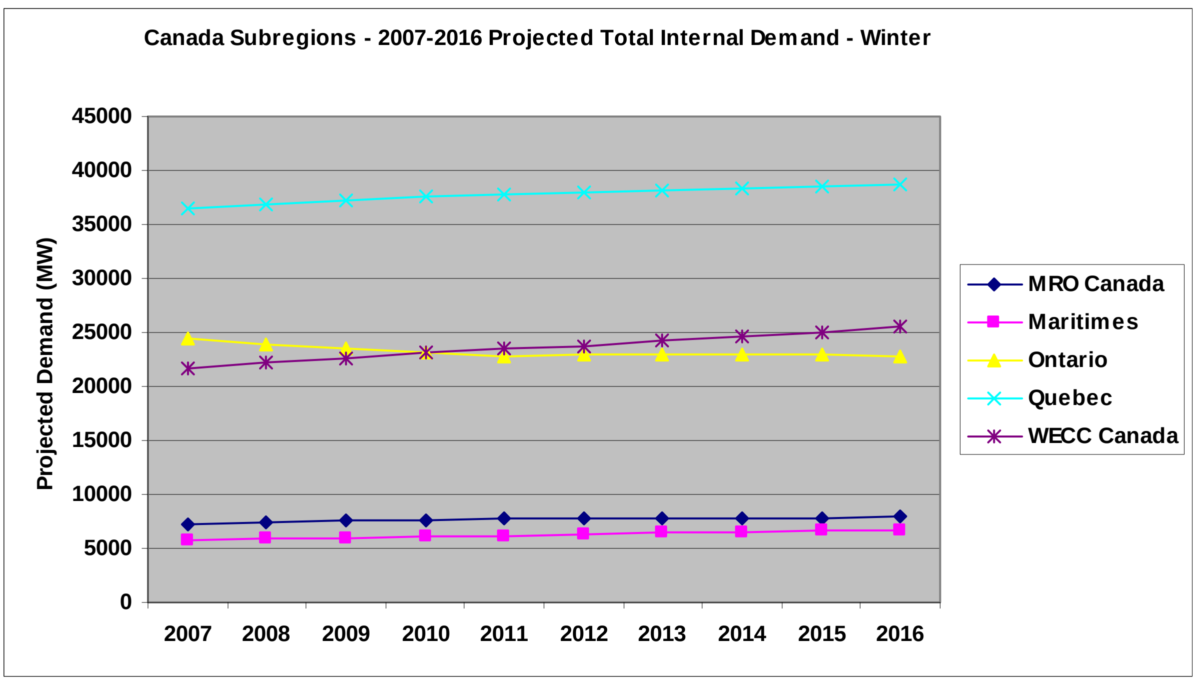
Canadian capacity margins raise in short term; remain steady for the long-term

Summer peak demand in the U.S. is forecast to increase over 135,000 MW or 17.7 percent in the next ten years with committed resources projected to increase 77,000 MW or 8.4 percent (including uncommitted resources, 123,000 MW or 12.7 percent). Winter peak demand for electricity in Canada is forecast to increase over 6,000 MW or 6.4 percent in the next ten years with committed resources projected to increase 11,000 MW (including uncommitted resources, 14,000 MW).

[21] Based on m EIA's United States summer/winter peak data in "Annual Energy Outlook 2007, with Projections to 2030"

The difference in demand growth between the U.S. and Canada can be predominantly attributed to the decrease in demand projected for the summer peaking Ontario province, forecasting a 0.2 percent reduction in summer peak and 0.7 percent reduction in winter peak each year during the 2007-2016 timeframe. Ontario's conservation and demand management[22] programs are expected to blunt much of the otherwise expected 0.7 percent growth during the study timeframe. This decrease offsets a portion of the increases in other Canadian provinces, such as WECC Canada (British Columbia and Alberta) and Quebec.





[22] http://www.powerauthority.on.ca/ipsp/Storage/33/2856_CDM_REVISED_Discussion_paper.pdf

Regional Reliability Assessment Highlights

The regional highlights below include an assessment of available and potential capacity margins along with supplemental information on regional activities in support of the NERC Transmission Planning (TPL) Standards[23] (see the *Reliability Concepts Used in this Report* section for capacity terminology definitions). Regional reliability assessment plans were reviewed by NERC staff for key regions/subregions fortifying the regional assessment provided below[24].

There is no single, fixed capacity margin throughout NERC. Target capacity margins vary between regions and within regions as these are set through regional and/or state/provincial agreements. In some regions, each state/province sets target levels, while in others, agreements between participants are signed towards specific capacity margin targets.

In some cases, capacity margins are dropping well below regional/subregional target levels or less then zero, especially for the long-term (six to ten years). Proposals for new generation and demand response programs have varying levels of certainty while load forecasts have higher levels of confidence. In some cases, the regional entities and their subregions did not submit generation additions with low certainty of development (as defined by the regions and subregions). The resulting capacity margins reflect the imbalance between the certainty of generation projections and relatively high confidence in load forecasts. Due to the short lead-time required for some types of capacity (i.e., wind and natural gas-fired turbines) the gap between projected increases in peak demand and capacity could be offset by assignment or development of capacity that has not yet been committed or announced[25].

The industry continues to grapple with how much of a wind generator's nameplate or highest manufacturer rated capacity should be counted on at time of peak. Consequently, though there is a significant increase in the number of wind farms and total wind nameplate capacity, only up to 1,800 MW of wind capacity is considered counted on to meet the peak demand. Available wind capacity at time of peak, when its output is needed the most, is often significantly less than nameplate capacity, and geographically varying.

In addition to capacity margin analysis, regional entities were asked to provide supplemental information on meeting NERC's TPL Standards as there is a tenuous connection between capacity margins and meeting NERC's TPL Standards. Namely, large capacity margins do not guarantee standards are met, while tight capacity margins do not necessarily indicate the TPL Standards will not be met. Often, where capacity margins are below target levels, regions/subregions add less certain, proposed units and transmission additions to perform NERC's TPL Standard evaluations. Depending on the regional entity, this generation/transmission is not always documented in the data provided to NERC, as there is low certainty of their construction.

---

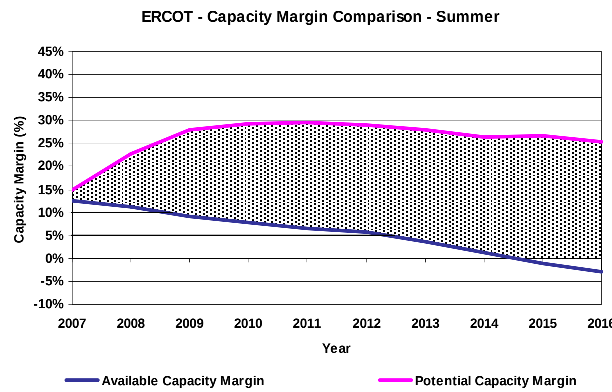
23 http://www.nerc.com/~filez/standards/Reliability_Standards.html

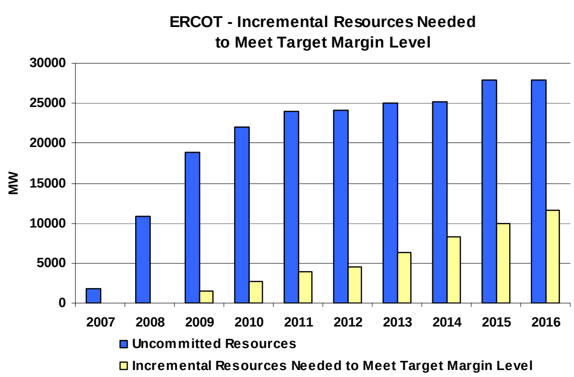
24 Note the net internal demand used for this analysis is based on data submitted to NERC. In most cases, it reflects a 50/50 non-coincident peak from each regional entity.

25 Detailed background data used in the preparation of this report is available in NERC's Electricity Supply & Demand (ES&D) database, 2007 edition (http://www.nerc.com/~esd/)

ERCOT

The 2007 long-term peak demand forecast for ERCOT is 0.7 percent higher than the 2006 assessment period. Although the projected demand growth rate is lower this year, the demand growth curve is shifted higher due to a one time adjustment in the economic outlook. ERCOT performs a 50/50 (top-down) forecast and a 90th percentile forecast that is 5.35 percent higher than the median. ERCOT reduces net internal demand by 1,112 MW of active demand response resources. ERCOT has a minimum reserve margin target of 12.5 percent, based on Loss-of-Load Expectation (LOLE) analysis of no more than one day in ten years, loss of load. Further, in the ten years ahead, there are currently interconnection agreements for 2,100 MW of new fossil fuel generation and 2,000 MW of wind generation. ERCOT has an adequate reserve margin through 2008. Over the long-term, reserve margins reported fall below the 12.5 percent minimum level, starting in 2009, based on new generation with signed interconnection agreements and existing resources. However, a significant number of interconnection requests for new generation are under review, along with possible mothball unit returns, and are likely to improve the reserve outlook.





Regarding ERCOT's uncommitted resources, there are over 6,000 MW of mothballed capacity and additional uncommitted resources under development, including 11,500 MW of non-wind and 14,000 MW of wind generation through 2016. A recent study conducted by ERCOT found that there are over 130,000 MW of potential wind resources throughout Texas and the Texas Public Utility Commission recently ordered ERCOT to develop transmission plans to integrate up to approximately 25,000 MW of installed wind capacity into ERCOT. A wind integration ancillary services impact study is underway. Further, owners of nuclear generation plants are developing a combined total of 6,176 MW in ERCOT through 2015. Preliminary studies concluded that a significant number of transmission system improvements would be required to handle the additional capacity of one of the proposed nuclear units as well as for the large amount of new wind generation.

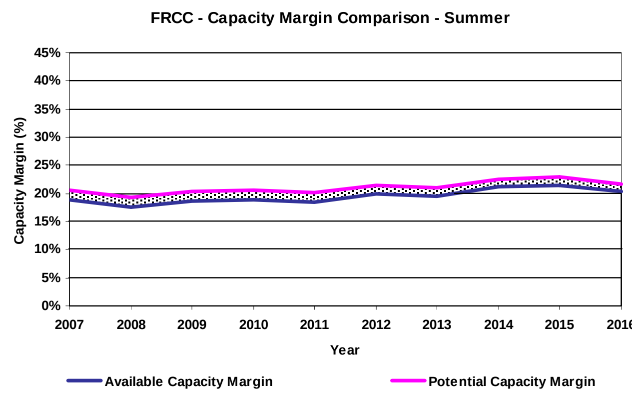
ERCOT and individual transmission owners develop a five-year plan for the ERCOT Region that is based on studies of system performance against ERCOT and NERC reliability standards. The results of this analysis are documented in the Annual ERCOT Report on Constraints and Needs. ERCOT also develops a Long-Term System Assessment (LTSA) in even-numbered years that investigates the long lead-time transmission system improvements needed to meet ERCOT and

NERC reliability standards through the tenth year of the planning horizon and performs studies in the odd-numbered years to validate the projects included in the LTSA allow the ERCOT System to meet applicable standards. Scenarios including new generation additions (based on uncommitted generation) and mothball unit return to service is included in the transmission needs analysis in order to ensure transmission adequacy in the assessment period.

FRCC

All Florida utilities are required to meet the Florida Public Service Commission reserve margin[26] and the Florida Reliability Coordinating Council (FRCC) reports adequate resources through 2016. Much of the resources in the six — ten year timeframe are not sited but are considered committed and deemed to be deliverable, representing FRCC's member obligation to meet this reserve margin.

Based on the aforementioned, the FRCC expects to have an adequate reserve margin with transmission system deliverability throughout the 2007–2016 reliability assessment to meet the forecasted growth in peak demand and energy through the same timeframe. The FRCC region expects to serve the forecasted firm peak demand and energy requirements reliably through 2016 by adding 17,991 MW of resources. In addition, uncommitted merchant plant capability of 1,146 MW is available as potential future resources of FRCC members and others.



The transmission capability within the FRCC is expected to be adequate to supply firm customer demand and to provide planned firm transmission service. In order to maintain an adequate transmission system, the FRCC members plan to construct 719 miles of 230 kV transmission lines through 2016. Operational issues in the Central Florida area are expected through the summer of 2010. Unplanned outages of generating units may aggravate the transmission system serving the Central Florida area. However, it is anticipated that existing operational procedures, pre-planning and training will adequately manage and mitigate the impacts to the bulk transmission system in the Central Florida area. After 2010, planned transmission improvements in the Central Florida area are expected to mitigate these operational issues.

The FRCC region meets NERC's TPL Standards by performing the required transmission assessments representing the ten-year planning horizon. The FRCC region develops detailed transmission assessments for the one — five year timeframe, recognizing the fact that generation expansion plans are known with a higher degree of confidence and most planned transmission projects and corresponding in-service dates are known. The FRCC region performs transmission assessments representing the six — ten year timeframe, recognizing the uncertainties related to

[26] FRCC uses reserve margins in their self-assessments, calculated against the base of load. The graph shows capacity margins that are calculated with a base of generation. Please see the *Reliability Concepts Used in this Report* Section for details on the definitions of each of these margins.

future generation siting and corresponding transmission expansion to support future generation and load growth. All Florida utilities are required to meet the Florida Public Service Commission reserve margin requirements. Therefore, even if future generation plans are not firm, the utilities must show they plan to maintain these reserve margin levels throughout the planning horizon. Many of the large generating units planned in the six — ten year timeframe are not sited and may require additional transmission sensitivity assessments.

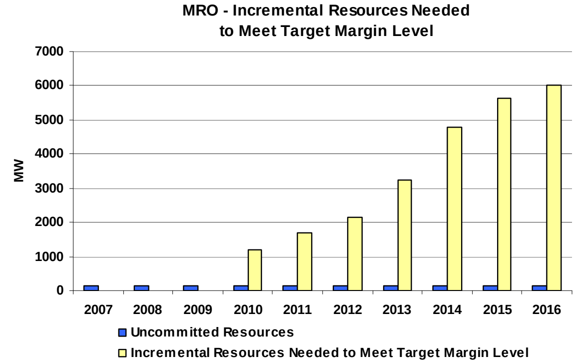
The FRCC transmission system is evaluated to identify possible emerging concerns, monitor known concerns, monitor the effects of planned projects and identify major projects that may require long lead times. The remedies developed for this section take into consideration the uncertainty of the generation expansion plan and the location and timing of projected loads. In addition, the transmission expansion plans representing the years six — ten of this study are typically under review by most transmission owners still considering multiple alternatives for each project.

MRO

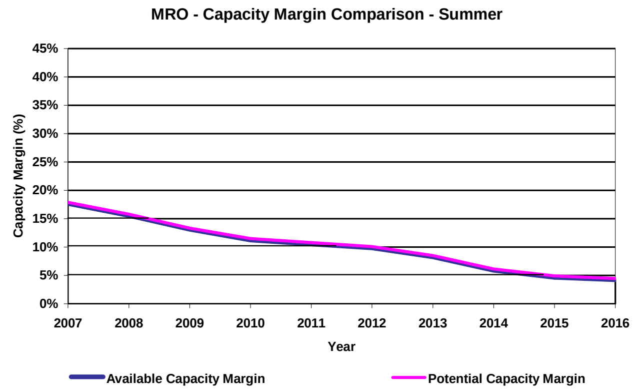
The data submitted by the Midwest Reliability Organization (MRO) indicates reduced capacity margins during the timeframe of this study. MRO-Canada has adequate generating capability throughout the assessment period, but currently planned capacity reported in the MRO-U.S. portion of the region is below MRO targets for reserve margins from 2010–2016.

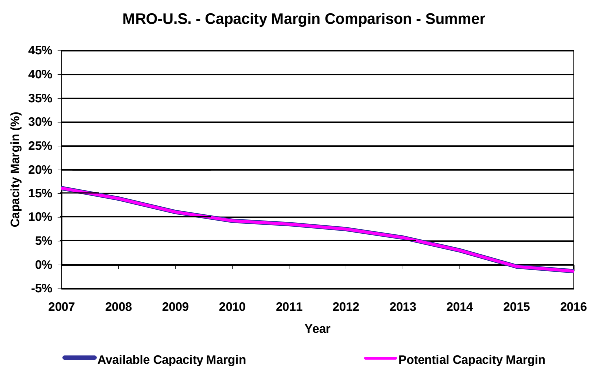
For the 2007–2016 period projected capacity margins are expected to be higher than reported by the regional entity to NERC based on past experience and the contractual enforcement mechanism for reserves within a large part of the MRO region. MRO members are accountable for meeting the planning reserve margins that apply to them. The MRO region is comprised of non-retail access jurisdictions (except the upper peninsula of Michigan) where MRO members have an “obligation to serve load” or “Provider of Last Resort”. In addition, the MRO is proposing a resource adequacy assessment standard that requires an annual load and capability assessment. Typically these members assess how best to meet their required margins by considering self-built generation, merchant generation, demand-side management, and firm power purchases with firm deliverability. In the six — ten year timeframe, the location and magnitude of future generation is less certain as lead-times are short for a number of generation types, including wind and gas turbines.

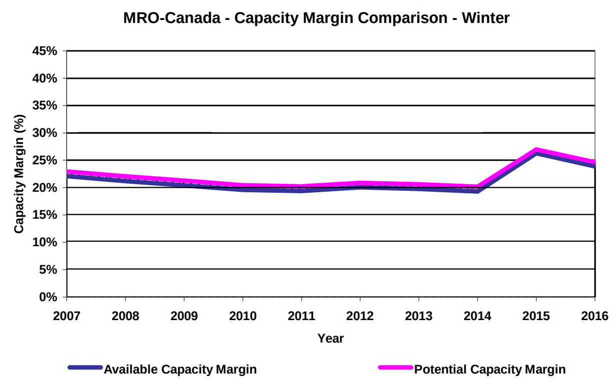
In this assessment, MRO projects only include committed generation projects (from Load and Capacity reports) that have a reasonable amount of certainty. Using only committed projects may lead to conservative predictions of reserve margin/criteria, especially in years six — ten. Historically MRO members have consistently met their reserve margins. To meet NERC’s TPL Standards, a ten-year model is built with assumptions made for future generation location using the best knowledge available including generation



interconnection queues and engineering judgment. Through the 2016 planning horizon, the MRO expects its transmission system to perform reliably assuming proposed reinforcements are completed on schedule. Power market activity will continue to fully use the capability of the system, which may not meet all market needs.



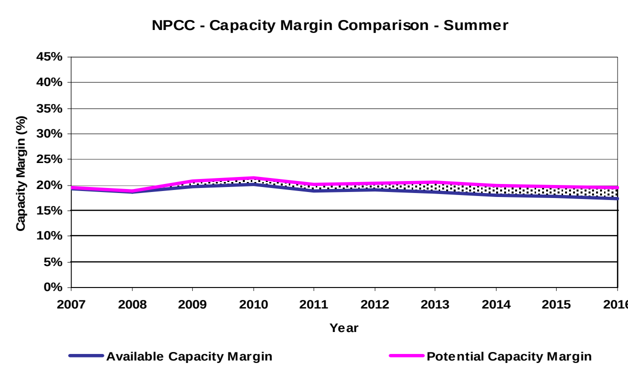




NPCC

To effectively conduct an assessment of resource adequacy, it is necessary to consider individually the five large Northeast Power Coordinating Council (NPCC) subregions: the Maritimes, New England, New York, Ontario and Québec, three of which are summer peaking and two of which are winter peaking. If one considers only the U.S. entities in NPCC (New York and New England), a significant drop in capacity margins over the assessment period is seen. NPCC-Canada (Maritimes, Québec and Ontario) shows a capacity margin growth until the year 2011, leveling at over 20 percent.

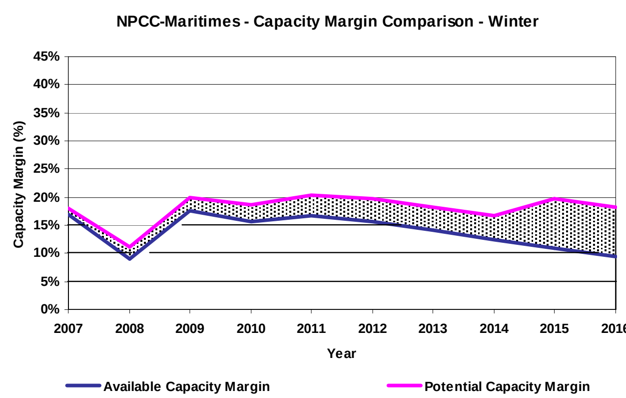
In New England, to meet NPCC criteria, approximately 170 MW are needed in 2009, increasing annually and requiring a total of 4,300 MW by the 2015/2016 time period. This amount is to be purchased by ISO-NE in the Forward Capacity Auction. Beginning in 2010, New York will require additional capacity to meet the NPCC adequacy criteria.



To meet NERC's TPL Standards, the assessment of transmission reliability and resource adequacy is directed to the five NPCC Areas: the Maritimes Area (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).

The NPCC has a comprehensive resource assessment program which is in place, directed through NPCC Document B-08, *Guidelines for Area Review of Resource Adequacy*[27]. This document charges the NPCC Task Force on Coordination of Planning to conduct periodic reviews of resource adequacy for the five NPCC Areas. In a similar manner, the NPCC Task Force on System Studies is charged with conducting periodic reviews of the reliability of the planned bulk power transmission systems of each area of NPCC and the transmission interconnections to other areas, the conduct of which is directed through NPCC Document B-04, *Guidelines for NPCC Area Transmission Reviews*[28].

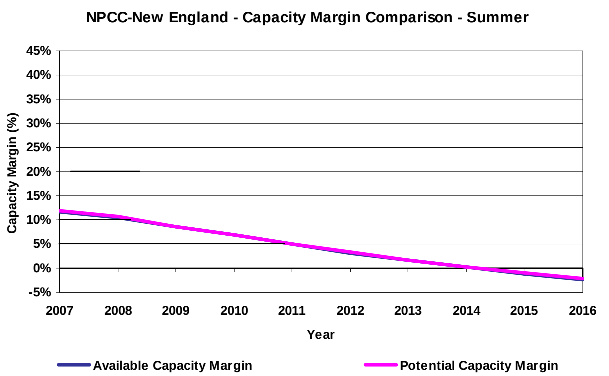
The NPCC Comprehensive Review is a thorough assessment of the area's entire bulk power transmission system, and it must be conducted by each area at least once every five years. In the years between NPCC Comprehensive Reviews, areas may conduct either an interim review or an intermediate review, depending on the extent of the system changes projected.

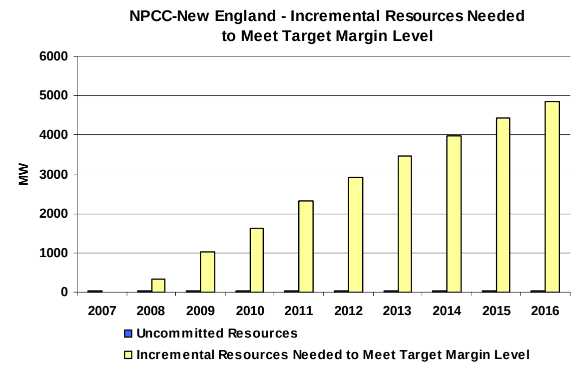


Maritimes — A 20 percent reserve criterion is required for the Maritimes to meet the NPCC resource adequacy criterion of Loss-of-Load-Expectation (LOLE) shall be no more than one-day-in-ten-years (0.1 days per year). The 20 percent regional reserve requirement in the Maritimes Area also accommodates load forecast uncertainty (i.e., higher peak demands) and instances of resource unavailability. Over the assessment period, the Maritimes Area will be below the 20 percent margin by 451 MW in 2008/09 due to the planned 18-month refurbishment of the 635 MW Point Lepreau nuclear generation station, scheduled from April of 2008 to October of 2009. Plans for replacement capacity through purchases to accommodate this refurbishment are still being evaluated by New Brunswick Power. Following the refurbishment of Pt. Lepreau, the Maritimes will meet the criterion except for a slight deficiency of 45 MW in the winter of 2014/15. In 2015/16, the criterion is met with the planned addition of 400 MW of conventional generation in Nova Scotia.

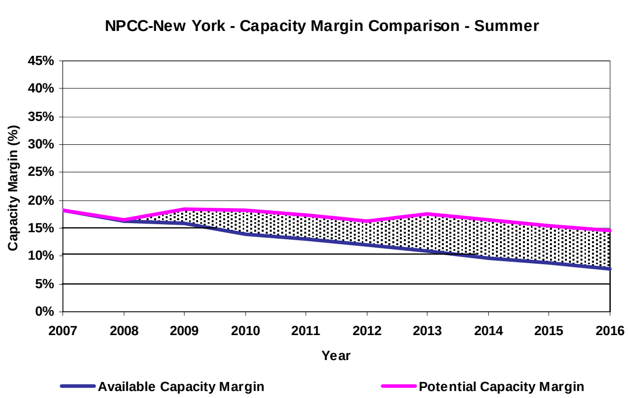
[27] https://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/new/B-08.pdf
[28] https://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/new/B-04.pdf

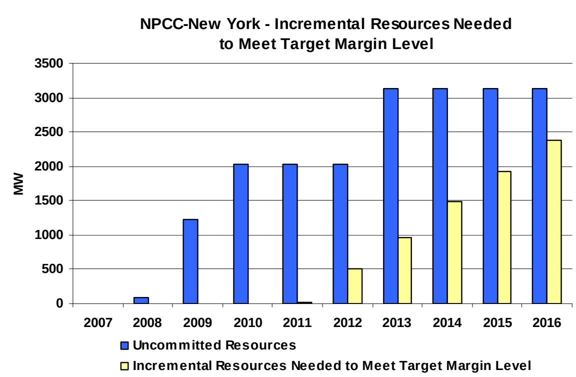
New England — ISO-NE anticipates it will meet the NPCC resource adequacy criterion of one-day-in-ten-years LOLE through 2008, assuming forecasted loads and capacity materialize and 2,000 MW of tie reliability benefits are available. Based on multi-area tie reliability benefits studies, this amount was determined to be 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 2008 in order to meet the reliability criterion. 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 the winter of 2015/2016. ISO-NE expects to purchase these resources in its Forward Capacity Auction.





New York — The NYISO conducts an annual Reliability Needs Assessment that examines both resource and transmission needs over a ten-year period. Resources totaling approximately 930 MW as well as transmission upgrades under construction or otherwise have met the screening criteria are included in the base case. This assessment determined sufficient statewide resources are available to meet NPCC LOLE criteria through the year 2010. For 2011, the assessment indicates resources would be sufficient if 250 MW were added to New York City (NYC), 500 MW were added in the Lower Hudson Valley, or if transfer limits into NYC were increased. Beyond 2011, additional resources of between 1,750 MW and 2,000 MW would be needed to meet the criteria through 2016. A majority of those resources are needed in the NYC zone.

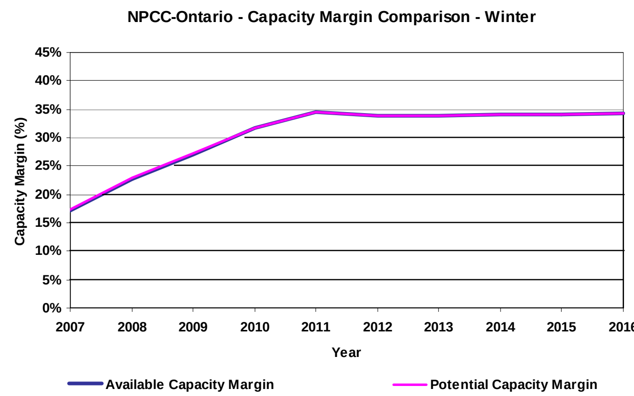




Subsequent to the RNA, the NYISO solicits solutions to address the identified needs. Sufficient market solutions as well as updated transmission owner's plans have been proposed to more than meet the needs through 2016. If sufficient market solutions are not proposed, the responsible transmission owners are obligated under the NYISO reliability planning process to implement regulatory backstops and/or gap solutions to meet any potential reliability shortfalls.

***Ontario* —** Under median demand growth assumptions, resources that are currently available within Ontario together with the forecast new generation and economic imports are sufficient to meet the NPCC regional resource adequacy criterion, from 2007–2016.

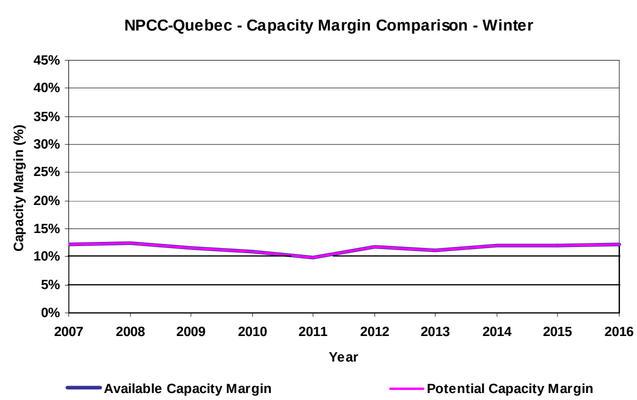
The planned shut down of Ontario's coal-fired generating stations is being managed by the Ontario Power Authority (OPA) and the Independent Electricity Service Operator (IESO). The schedule for retirements is part of OPA's integrated power system plan filed recently with the Ontario Energy Board (OEB) and will take place in 2014 under provincial regulation. In 2006, generation from coal-fired facilities was down three percent from the previous year. As new facilities come into service and conservation and demand management program activities progress, reliance on coal to meet demand in Ontario can continue to decline, and ultimately lead to shutdown in 2014.



IESO adequacy assessments include only those projects that are under construction or that have power supply contracts with the OPA. Additional demand measures and supply additions are identified as part of the integrated power system plan and will be included as future resources once contractual arrangements are in place. The IESO target is an available reserve margin of about 16 percent above the summer peak demand based on monthly normalized weather impacts. The IESO does not include imports (up to 4,000 MW transfer capability) or the use of emergency operating procedures (about 900 MW from voltage reduction, public appeals and emergency load reduction programs) in assessing supply against this requirement. The IESO does assume fossil generation temperature deratings, wind deratings (90 percent), and hydroelectric water limitations, all three of which total about 3,300 MW. Planned outages are permitted only if reserve margins allow, in which case their impacts are assessed as well.

Resources available within Ontario are generally expected to be adequate, but deficiencies could arise as a result of higher than forecast generator outages, prolonged extreme weather conditions and other influencing factors. Available imports to supplement internal generation are expected to be sufficient to meet the Ontario demand under these circumstances.

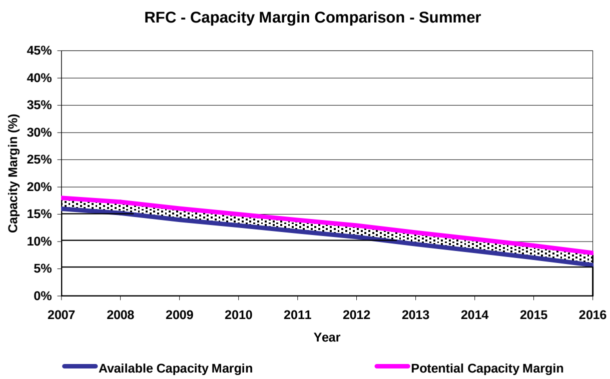
***Québec* —** In the *2006 Québec Area Interim Review of Resource Adequacy*, Québec demonstrated that the installed reserve margin requirement, expressed as a percentage of the peak load, needs to be slightly above 10 percent to comply with the NPCC adequacy criterion. In this long-term assessment, the planned reserves are close to 14 percent except for the period of time the Gentilly 2 nuclear unit will be out of service for refurbishment. The installed reserve margin percentage will be between 12 and 13 percent

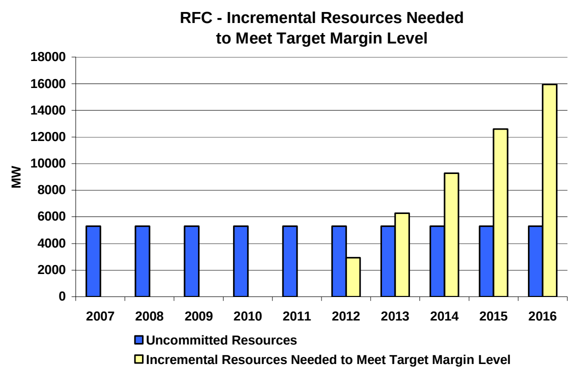


during the Gentilly outage. In the case of a high load forecast scenario, Québec still meets the NPCC resource adequacy criterion (LOLE less than 0.1 day per year).

RFC

The bulk power systems in the Reliability*First* (RFC) Region are expected to perform well in meeting the forecast demand obligations over a wide range of anticipated system conditions, as long as established operating limits and procedures are followed and proposed projects are completed in a timely manner. Major transmission line projects have been announced that are expected to enhance reliability of the transmission network in eastern areas of RFC. Reliability*First's* target for resource adequacy should be satisfied throughout the first half of the assessment period. Proposed capacity additions and existing capacity, including uncommitted resources, could potentially satisfy a target 15 percent reserve margin through 2012, if the transmission system is capable of fully delivering those resources.

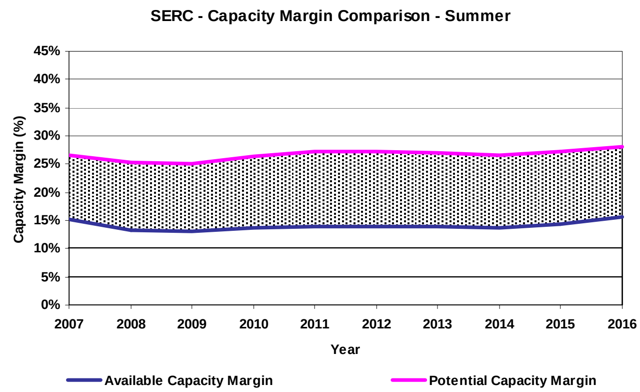




These reserve margins include over 7,800 MW of existing uncommitted capacity and projected capacity additions. Starting in 2013, additional capacity resources are needed to maintain an overall RFC target 15 percent reserve margin. The amount of needed capacity resources ranges from 1,500 MW in 2013 to 11,100 MW in 2016. There is currently no certainty with the location and ownership of these required additional resources and; therefore, no unit information was included in the data provided to NERC.

SERC

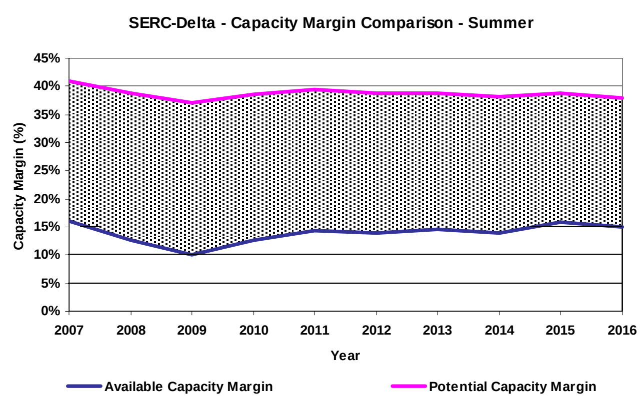
Significant generation development has occurred in the SERC region during the past few years, resulting in thousands of MW of uncommitted generating capacity. Some of this generation can be made available as short-term, non-firm or potential future resources to SERC members and others. Although the SERC region does not implement a regional reserve requirement, members adhere to their respective state commissions' regulations or internal business practices as they plan for adequate generation resources. SERC members use various methodologies to ensure adequate resources are available and deliverable to the load.



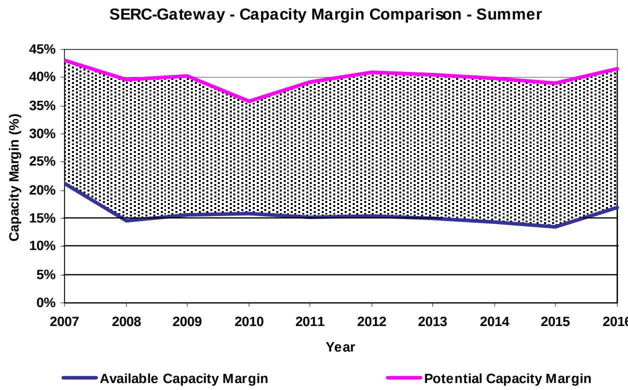
SERC has several layers of NERC TPL Standard assessment studies. The individual transmission owners within SERC conduct assessment studies to ensure compliance of their individual system which are subsequently SERC audits and SERC assesses the results. Some subregions (like VACAR) conduct assessment studies of the entire subregion to ensure simultaneous compliance of the systems within the subregion. Further, SERC has study groups that conduct assessment studies of the entire region to ensure simultaneous compliance of all the systems within the region.

To meet individual capacity margin requirements, SERC members use request for proposals and internal analyses to determine how future resource needs will be met. The results of this analysis may be self-build generation, power purchases from existing non-committed generation, or new IPP construction.

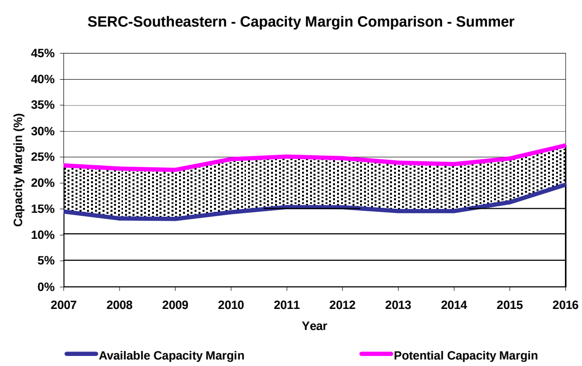
***Delta (formerly Entergy)* —** Projected capacity margin was 15.2 percent for the 2007 summer, dips to about 10 percent for a year and then rebounds to around 14–15 percent for the remainder of the ten-year period. There are large amounts of uncommitted generation in the subregion that could provide additional capacity when necessary. The one-year dip in capacity margin is a result of resources subregion members are currently evaluating and thus were not reported. The rebound is due to planned network resources for those outward years.



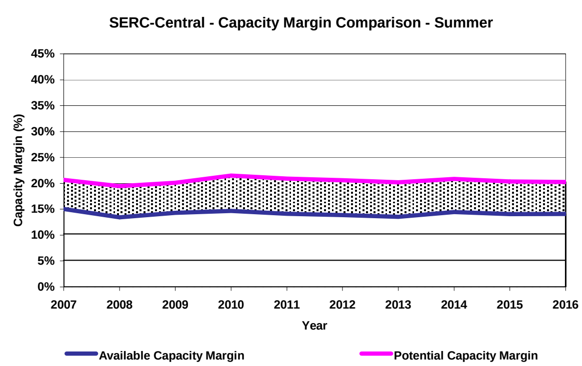
***Gateway* —** Projected capacity margin for the Gateway subregion was 21.3 percent for the 2007 summer, and is expected to decline gradually to approximately 10 percent over the remainder of the planning period assuming continuation of the existing Illinois Auction process that has no long-term capacity purchase requirements. However, at the time of this writing the process for procuring capacity resources to meet the demand and reserve requirements in Illinois is under review by the Illinois legislature and will likely change. Historically, the major utilities in the subregion have maintained a planning reserve margin of approximately 15 percent, and maintaining planning reserves at these levels is expected to be achieved considering the large amount of existing uncommitted capacity in the subregion and in neighboring regional entities. In addition to the 1,650 MW Prairie State coal-fired merchant plant development in 2011, generation developers representing over 1,000 MW of coal-fired generation and 4,000 MW of wind generation have requested interconnection service in the subregion within the next five years. Most of these proposed developments are in Illinois, and are in various stages of study and negotiation.



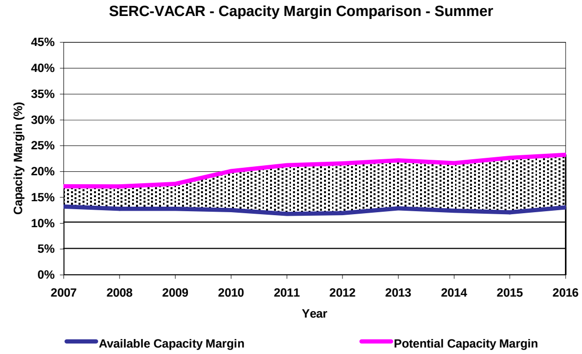
***Southeastern (formerly Southern)* —** Projected capacity margin was forecast to be 14.3 percent for the 2007 summer, and remains at or above 13 percent over the entire planning period.



***Central (formerly TVA)* —** Projected capacity margin was 13.4 percent for the 2007 summer, and ranges from 11.8 percent to 13.2 percent over the remainder of the planning period. In addition to the restart of Browns Ferry Nuclear Unit 1 (1,280 MW), TVA has recently purchased the combustion turbine (CT) plants, Marshall (640 MW) and Gleason (510 MW) from an independent power producer (IPP). Additional resource expansion is expected to be confirmed in the near future.

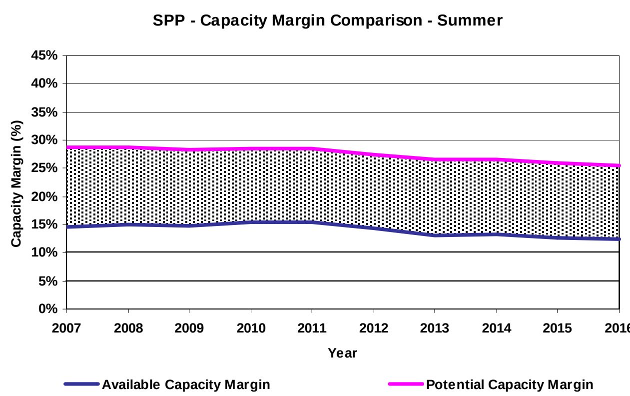


VACAR **—** Projected capacity margin was 13.1 percent for the 2007 summer, and ranges from 11.7 percent to 13.0 percent over the remainder of the planning period.



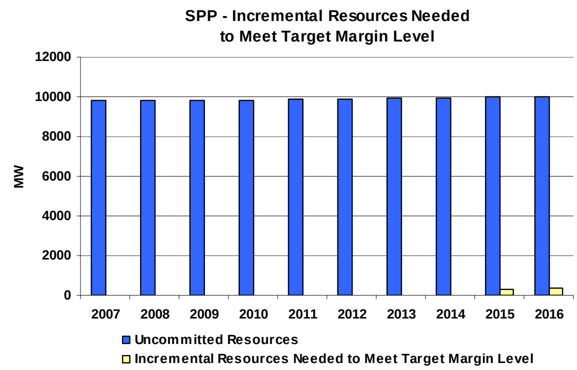
SPP

Based on historical trends, SPP anticipates installation of around 10,000 MW in nameplate capacity over the next ten years, 70 percent of which is expected to be fossil fueled. The remaining 30 percent is anticipated to be wind-driven generation. SPP test data for a supply adequacy audit performed in the first quarter of 2007, the capacity of these wind-farms can only be expected to contribute between zero and 20 percent of nameplate rating during peak loading periods. SPP Criterion 2.1.9 requires members maintain a 12 percent capacity margin unless their system is primarily hydro-based where the required margin is lowered to nine percent. Because wind and hydro capacity make up a small portion of SPP's capacity, these minimum capacity margin requirements are sufficient to cover a 90/10 weather scenario and the instability issues associated with a high penetration of wind-based generation. Again, results of 2007 supply adequacy audit have qualified SPP's processes for estimating existing and future generation capacities.



These capacity margin projections include the effects of demand-side response programs, such as direct-control load management and interruptible demand. Available demand relief from direct-control load management programs are expected to rise from 15 MW in the summer of 2007, to 54 MW in 2016. Additionally over the next ten years, interruptible demand relief is also expected to increase from 746 MW to 787 MW. SPP views demand-side management programs as beneficial to consumers and has determined that increasing availability of these programs to consumers as one of the top priorities going forward.

To meet NERC's TPL Standards, SPP's Model Development Working Group develops 16 power flow models ranging from year one through year ten. These models reflect load demand for all seasons (i.e. summer peak, shoulder peak, winter peak, spring peak and light load). SPP's planning group conducts a detailed contingency analysis and mitigation plans, if required, are proposed. After incorporating stakeholder comments, the final plan is approved by the SPP Board of Directors, which authorizes and directs construction of these transmission upgrades. The latest SPP Transmission Expansion Plan is posted at the SPP web site.[29]



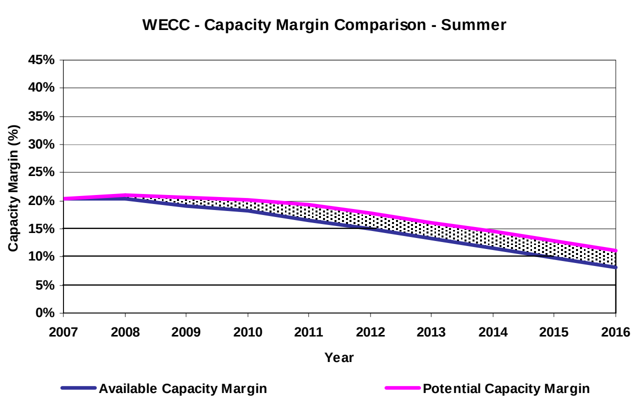
Under the SPP membership agreement and criteria, participants are responsible for providing evidence they have obtained generation capacity for the next ten years to maintain a 12 percent capacity margin. SPP staff conducts a supply adequacy audit (every five years) to verify the data submitted.

WECC

By 2011, reported margins in the southern portion of the WECC are projected to be below desired planning reserves.

The data for this assessment is provided by all the balancing authorities within the Western Interconnection and is processed by WECC's staff under the direction of WECC's Loads and Resources Subcommittee. This year, the subcommittee chose to categorize resource additions according to their status:

- Class 1 (committed) resources are defined as all resources presently under active construction (or committed for re-rating) with expected in-service dates before January 2011 and totals 8,603 MW (summer capacity).
- Class 2 is composed primarily of uncommitted resources and is an additional 6,153 MW (summer capacity) reported as currently undergoing regulatory approval and with in-service dates before January 2013.
- Class 3 contains a total of 34,020 MW of resources that generally have identified in-service dates and locations but do not fall into the previous two categories.



Class 3 resources were excluded from WECC's data submittal, graphics, and assessment because they were considered by WECC's Loads and Resources Subcommittee to be too speculative at this time. Additional proposed projects without identified locations and/or in-service dates are excluded from the Class 3 data. WECC intends the Class 3 designation to highlight the need for investment in the future and/or the need for further development of demand-side or

[29] http://www.spp.org/publications/2006%20Expansion%20Plan%20Report_12_11_06_approved_TWG_sj_1-3-07_PUBLIC.pdf

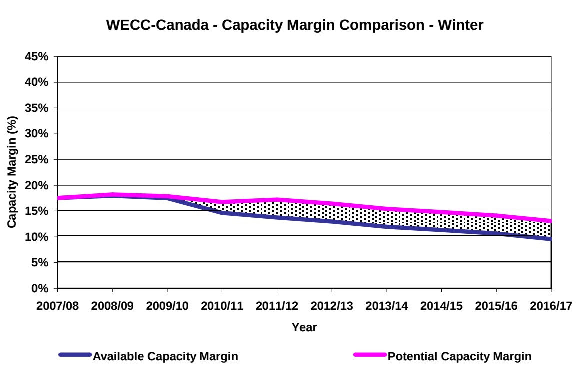
supply-side resources.

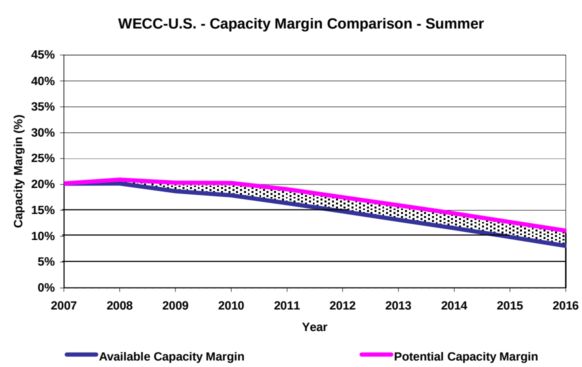
The shortfall in planning reserves in the California-Mexico (CA-MX), Rocky-Mountain Power Area (RMPA) and Arizona-New Mexico-Southern Nevada (AZ-NM-SNV) is due to the intentional exclusion of Class 3 resources, the lack of Class 1 or 2 resources being built and congestion on the north-south intertie. There are several options to address this problem: 1) add more resources locally, 2) further develop demand-side resources, and/or 3) increase the transfer capability from north-to-south to support the CA-MX, RMPA and AZ-NM-SNV areas. Increasing the transfer capability alone; however, would not be enough as there could be severe energy limits associated with the hydro resources in the Northwest.

Planning authorities and the transmission planners are responsible for ensuring their areas are compliant with the TPL Standards 001–004. When the planning authorities and the transmission planners have created their data sets and successfully run their simulations, they forward their data to the WECC. WECC’s System Review Working Group compiles and develops a WECC-wide base case under TPL-005-0.

The WECC Annual Study Program provides base cases for WECC members, WECC staff, and ongoing reliability and risk assessment of the existing and planned western interconnected electric system for the next ten years. To achieve this goal in 2006, ten new power flow base cases were compiled and 35 disturbances were simulated. Five power flow cases were prepared to conduct operating studies and the remaining five prepared to simulate various planning scenario cases through 2016. Disturbance simulations emphasize multiple contingency (N-2) outages (units and branches). Severe disturbances are simulated including loss of entire substations and generating plants to identify potential deficiencies leading to unacceptable system performance. The intent is to model system performance under stressed conditions with contingencies that might not normally be considered in operations and long-term planning studies, to identify potential concerns requiring further investigation. (Refer to *WECC’s Self-Assessment* section for a general comparison of the assessment data to the data used for the TPL–005–0 studies.)

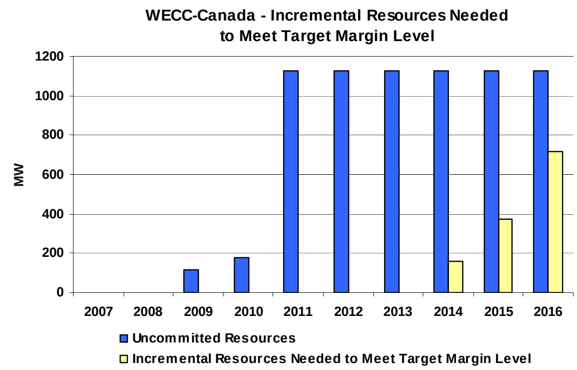
For this assessment, WECC provides the generation and firm transaction data it received as described above, but the results of a least-cost dispatch program called Supply Adequacy Model, are used to determine any diversity exchanges (“non-contracted” purchases and sales) that may occur.





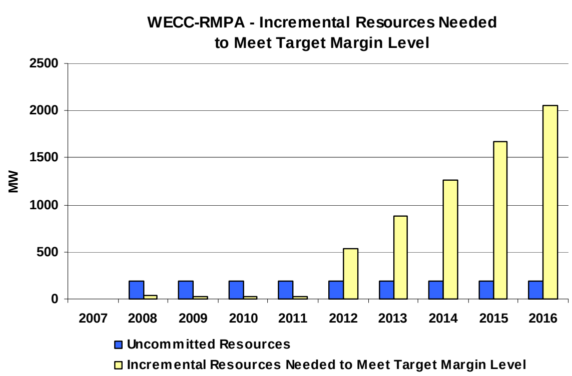
There is no guarantee any of the projects are currently projected to be built whether in the Power Flow Studies and this assessment will be built regardless of the class, but there is a higher likelihood for projects classified as Class 1 and 2 due to the schedules and current activity. As the need for more capacity grows, projects should become more active and their status will change, which in turn will advance projects to Class 1 or 2. All graphics and tables that refer to "potential capacity" only include WECC's Class 1 and Class 2 generation, unless otherwise indicated.

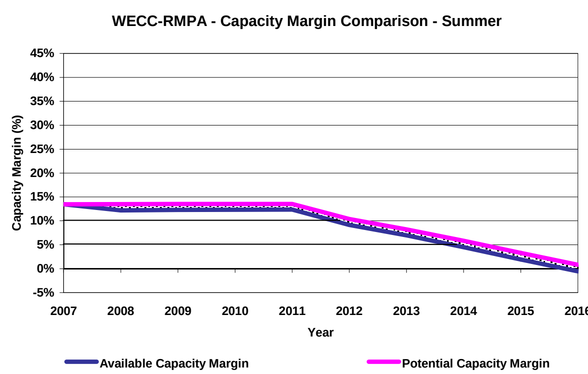
Northwest Power Pool Area — Much of the WECC's forecast surplus capacity margin exists due to the Columbia River Basin hydroelectric dams located in the NWPP-U.S., but deliverability to other areas is problematic due to both the constrained north-to-south transfer capability and the limited energy associated with the hydro storage.



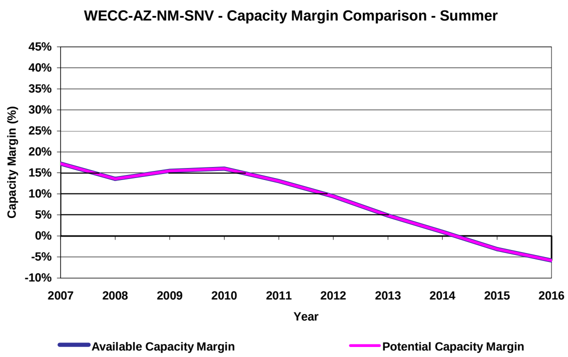
Northwest Power Pool Area-Canada winter capacity margins are tight, dropping below the subregional planning reserve margin in the winter of 2009-2010. The Canadian entities are aware of the resource adequacy issue for their areas and have instituted very active resource acquisition and transmission reinforcement processes.

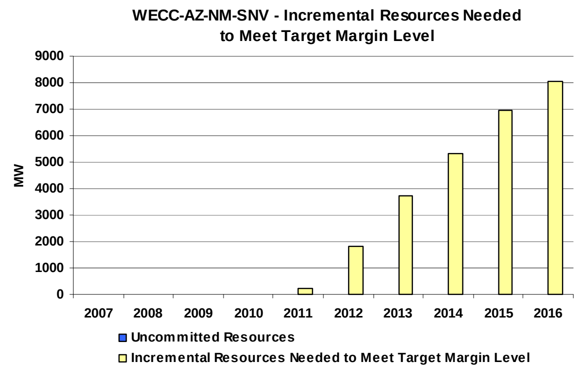
Rocky Mountain Power Area — The data for the Rocky Mountain Power Area indicated suitable capacity margins until 2011. Thereafter, there are insufficient resources in the southern portion of the Interconnection to sustain the planning capacity margin, and it begins drops below zero in 2016. In 2016, the shortfall between the load and planned margin versus the projected capacity is 1,822 MW. Of the 34,020 MW of Class 3 generation, 2,223 MW are projected.





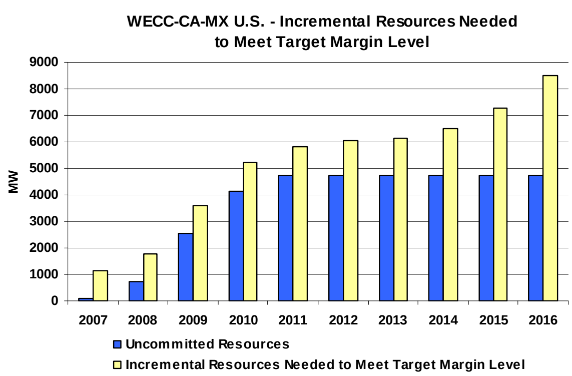
Arizona-New Mexico-Southern Nevada Power Area — When looking at access to potential resources in the NWPP subregion, the AZ-NM-SNV subregion would also have to be concerned with Path-26 limitations in California as well as the north-to-south limitation at the California-Oregon border. Currently are very few Class 1 and 2 resources available in this area to back-stop adequacy. The capacity margin for the area demonstrates the subregion faces a limited window of opportunity to address area resource adequacy issues. In 2016, the shortfall between the load and planned margin versus the projected capacity is 7,646 MW. Of the 34,020 MW of Class 3 generation, 3,028 MW are projected for the AZ-NM-SNV Area.

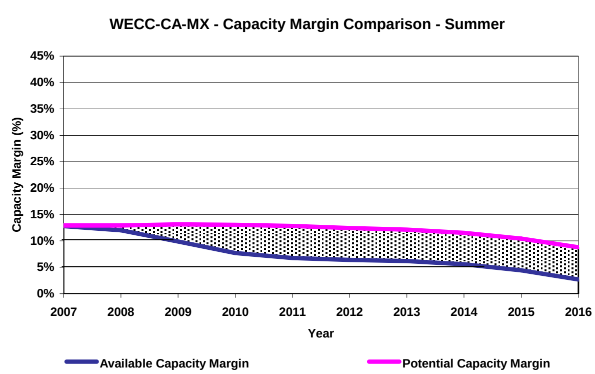




California-Mexico Area **—** This area's capacity margins remain tight and also reflect the congested north-south transfer corridor limitations. Substantially more resources must be built and be deliverable to ensure adequacy is sustained. In 2016, the shortfall between the load and planned margin versus the projected resources is 5,358 MW — which doesn't account for importing 1,375 MW of non-contracted purchases. Of the 34,020 MW of Class 3 generation, 24,540 MW are projected for the California-Mexico Area (but are not included in the data submitted, shown in the graphics or used in capacity margin calculations). California generally peaks in August, but first is projected to be below its planned reserve margin in July of 2011, whereas the state meets its planned reserve margin in August. This may be attributed to WECC having its regional peak in July, so there is less capacity available for non-contracted purchases. The state has implemented a mandatory resource adequacy program for the California ISO (CAISO) load control area requiring load-serving entities to procure 115 percent of their forecast demand 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.

Recently, a Californian coalition of water users filed a notice on its intent to file a lawsuit alleging Mirant Corp.'s natural gas-fired power plants in Antioch and Pittsburg are harming fish including the delta smelt in the Sacramento-San Joaquin Delta.[30,31]





[30] http://www.thebusinessjournal.com/index.php?option=com_content&task=view&id=875&Itemid=148
[30] http://www.californiaprogressreport.com/2007/06/delta_smelt_fir.html
[31] http://www.californiaprogressreport.com/2007/06/delta_smelt_fir.html

Table 3a: Estimated 2007 Summer Resources and Demands (MW) with Margins (%)[32]

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	W/O Uncommitted Available Capacity Margin (%)	With Uncommitted Potential Capacity Margin (%)
United States					
ERCOT	62,669	71,736	1,868	12.6	14.9
FRCC	43,824	54,029	1,146	18.9	20.6
MRO	41,754	49,792	0	16.1	16.1
NPCC	59,727	70,607	18	15.4	15.4
New England	27,360	31,004	18	11.8	11.8
New York	32,367	39,603	0	18.3	18.3
RFC	180,400	217,156	5,300	16.9	18.9
SERC	196,111	231,123	36,115	15.1	26.6
Central	41,325	48,651	3,442	15.1	20.7
Delta	27,241	32,420	13,666	16.0	40.9
Gateway	18,820	23,913	9,150	21.3	43.1
Southeastern	48,145	56,328	6,540	14.5	23.4
VACAR	60,580	69,811	3,317	13.2	17.2
SPP	42,266	49,480	9,818	14.6	28.7
WECC	134,089	167,932	0	20.2	20.2
AZ-NM-SNV	30,086	36,322	0	17.2	17.2
CA-MX US	56,925	65,280	0	12.8	12.9
NWPP	35,803	48,489	0	26.2	26.2
RMPA	11,343	13,109	0	13.5	13.5
Total-United States	**760,840**	**911,855**	**54,265**	**16.6**	**21.3**
Canada					
MRO	5,729	7,827	100	26.8	27.7
NPCC	50,644	66,156	72	23.4	23.8
Maritimes	3,349	6,218	72	46.1	46.8
Ontario	25,526	28,552	0	10.6	11.2
Quebec	21,769	31,386	0	30.6	30.6
WECC	17,128	20,993	0	18.4	18.4
Total-Canada	**73,501**	**94,976**	**172**	**22.6**	**22.9**
Mexico					
WECC CA-MX Mex	2,097	2,406	0	12.8	12.8
Total-NERC	**836,438**	**1,009,237**	**54,437**	**17.1**	**21.4**

[32] See notes to Tables 3a through 3f. Uncommitted generation may not be deliverable, though potential capacity margins assume the generation is deliverable.

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

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	W/O Uncommitted Available Capacity Margin (%)	With Uncommitted Potential Capacity Margin (%)
United States					
ERCOT	46,038	72,031	7,217	36.1	41.9
FRCC	45,993	57,762	1,227	20.4	22.0
MRO	34,582	46,959	0	26.4	26.4
NPCC	48,394	76,110	19	36.4	36.4
New England	23,070	34,213	19	32.6	32.6
New York	25,324	41,897	0	39.6	39.6
RFC	147,800	219,407	5,300	32.6	34.2
SERC	173,036	231,917	36,115	25.4	35.4
Central	40,349	47,878	3,442	15.7	21.4
Delta	22,652	32,875	13,666	31.1	51.3
Gateway	14,513	23,177	9,150	37.4	55.1
Southeastern	40,302	55,798	6,540	27.8	35.3
VACAR	55,220	72,189	3,317	23.5	26.9
SPP	30,469	50,070	10,318	39.1	49.5
WECC	107,738	167,984	453	35.9	36.1
AZ-NM-SNV	18,786	36,710	0	48.8	48.8
CA-MX US	40,446	60,951	0	33.6	33.8
NWPP	39,777	57,560	450	30.9	31.4
RMPA	9,687	11,306	3	14.3	14.3
Total-United States	**634,050**	**922,240**	**60,649**	**31.2**	**35.5**
Canada					
MRO	7,004	8,991	100	22.1	23.0
NPCC	64,538	75,491	72	14.5	14.7
Maritimes	5,394	6,501	72	17.0	17.9
Ontario	24,120	29,076	0	17.0	17.3
Quebec	35,024	39,914	0	12.3	12.3
WECC	21,381	25,924	0	17.5	17.5
Total-Canada	**92,923**	**110,406**	**172**	**15.8**	**16.0**
Mexico					
WECC CA-MX Mex	1,549	2,057	0	24.7	24.7
Total-NERC	**728,522**	**1,034,703**	**60,821**	**29.6**	**33.5**

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

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	W/O Uncommitted Available Capacity Margin (%)	With Uncommitted Potential Capacity Margin (%)
United States					
ERCOT	68,331	72,993	23,958	6.4	29.5
FRCC	48,016	58,906	1,146	18.5	20.0
MRO	46,118	50,445	0	8.6	8.6
NPCC	63,696	70,320	2,047	9.4	12.0
New England	29,635	31,175	18	4.9	5.0
New York	34,061	39,145	2,029	13.0	17.3
RFC	191,300	220,199	5,300	13.1	15.2
SERC	212,603	246,919	44,838	13.9	27.1
Central	44,882	52,262	4,487	14.1	20.9
Delta	29,561	34,532	14,198	14.4	39.3
Gateway	19,634	23,170	9,145	15.3	39.2
Southeastern	53,403	63,116	8,177	15.4	25.1
VACAR	65,123	73,839	8,831	11.8	21.2
SPP	45,711	54,108	9,889	15.5	28.6
WECC	145,168	173,628	5,626	16.4	19.1
AZ-NM-SNV	33,464	38,487	0	13.1	13.1
CA-MX US	60,502	64,765	4,617	6.6	12.9
NWPP	38,882	51,226	815	24.1	25.3
RMPA	12,389	14,134	194	12.3	13.5
Total-United States	**820,943**	**947,518**	**92,804**	**13.4**	**21.1**
Canada					
MRO	6,168	8,006	100	23.0	23.9
NPCC	51,590	71,910	257	28.3	28.5
Maritimes	3,563	6,331	257	43.7	45.9
Ontario	25,442	33,016	0	22.9	22.9
Quebec	22,585	32,563	0	30.6	30.6
WECC	18,667	21,640	1,125	13.7	18.0
Total-Canada	**76,425**	**101,556**	**1,482**	**24.7**	**25.8**
Mexico					
WECC CA-MX Mex	2,624	2,931	0	10.5	10.5
Total-NERC	**899,992**	**1,052,005**	**94,286**	**14.4**	**21.5**

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

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	W/O Uncommitted Available Capacity Margin (%)	With Uncommitted Potential Capacity Margin (%)
United States					
ERCOT	49,922	76,812	24,839	35.0	50.9
FRCC	50,064	63,279	1,227	20.9	22.4
MRO	38,108	49,162	0	22.5	22.5
NPCC	50,921	75,922	2,454	32.9	35.0
New England	24,265	34,203	19	29.1	29.1
New York	26,656	41,719	2,435	36.1	39.6
RFC	156,000	222,408	5,300	29.9	31.5
SERC	185,661	242,897	44,838	23.6	35.5
Central	42,627	51,326	4,487	16.9	23.6
Delta	24,549	34,231	14,198	28.3	49.3
Gateway	15,157	20,840	9,145	27.3	49.5
Southeastern	44,501	61,244	8,177	27.3	35.9
VACAR	58,827	75,256	8,831	21.8	30.0
SPP	32,958	54,416	10,389	39.4	49.1
WECC	114,984	169,803	5,638	32.3	34.5
AZ-NM-SNV	20,847	39,060	0	46.6	46.6
CA-MX US	41,820	58,709	4,617	28.8	34.1
NWPP	42,583	60,284	828	29.4	30.3
RMPA	10,592	12,180	194	13.0	14.4
Total-United States	**678,618**	**954,699**	**94,685**	**28.9**	**35.3**
Canada					
MRO	7,435	9,221	100	19.4	20.2
NPCC	64,490	81,480	306	20.9	21.1
Maritimes	5,749	6,906	306	16.8	20.3
Ontario	22,540	34,410	0	34.5	34.5
Quebec	36,201	40,164	0	9.9	9.9
WECC	23,139	26,829	1,125	13.8	17.2
Total-Canada	**95,064**	**117,530**	**1,531**	**19.1**	**20.2**
Mexico					
WECC CA-MX Mex	1,938	2,395	0	19.1	19.1
Total-NERC	**775,620**	**1,074,624**	**96,216**	**27.8**	**33.8**

Table 3e: Estimated 2016 Summer Resources and Demands (MW) and Margins (%)

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	W/O Uncommitted Available Capacity Margin (%)	With Uncommitted Potential Capacity Margin (%)
United States					
ERCOT	75,899	73,757	27,858	-2.9	25.3
FRCC	53,487	67,169	1,146	20.4	21.7
MRO	50,549	49,903	0	-1.3	-1.3
NPCC	67,946	70,270	3,147	3.3	7.5
New England	31,885	31,175	18	-2.3	-2.2
New York	36,061	39,095	3,129	7.8	14.6
RFC	205,300	220,150	5,300	6.7	8.9
SERC	233,569	276,936	47,685	15.7	28.0
Central	49,630	57,762	4,487	14.1	20.3
Delta	32,486	38,172	14,198	14.9	38.0
Gateway	20,611	24,795	10,423	16.9	41.5
Southeastern	59,884	74,587	7,753	19.7	27.3
VACAR	70,958	81,620	10,824	13.1	23.2
SPP	49,786	56,911	9,989	12.5	25.6
WECC	159,428	173,536	5,626	8.1	11.1
AZ-NM-SNV	37,978	35,885	0	-5.8	-5.8
CA-MX US	65,307	67,705	4,617	3.5	9.8
NWPP	42,251	50,298	815	16.0	17.3
RMPA	13,892	13,817	194	-0.5	0.8
Total-United States	**895,964**	**988,632**	**100,751**	**9.4**	**17.8**
Canada					
MRO	6,317	9,283	100	32.0	32.7
NPCC	52,289	75,232	1,358	30.5	31.2
Maritimes	3,909	6,544	758	40.3	46.5
Ontario	25,066	33,875	0	26.0	26.0
Quebec	23,314	34,813	600	33.0	33.0
WECC	20,422	22,317	1,125	8.5	12.9
Total-Canada	**79,028**	**106,832**	**2,583**	**26.0**	**27.4**
Mexico					
WECC CA-MX Mex	3,425	2,931	0	-16.9	-16.9
Total-NERC	**978,417**	**1,098,395**	**103,334**	**10.9**	**18.5**

Table 3f: Estimated 2016/2017 Winter Resources and Demands (MW) and Margins (%)

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	W/O Uncommitted Available Capacity Margin (%)	With Uncommitted Potential Capacity Margin (%)
United States					
ERCOT	56,053	76,832	27,939	27.0	46.5
FRCC	56,274	72,102	1,227	22.0	23.3
MRO	41,377	49,179	0	15.9	15.9
NPCC	54,234	75,872	3,554	28.5	31.7
New England	25,620	34,203	19	25.1	25.1
New York	28,614	41,669	3,535	31.3	36.7
RFC	165,500	222,419	5,300	25.6	27.3
SERC	201,706	269,099	47,685	25.0	36.3
Central	45,749	54,225	4,487	15.6	22.1
Delta	27,106	37,871	14,198	28.4	47.9
Gateway	15,966	22,282	10,423	28.3	51.2
Southeastern	49,720	72,368	7,753	31.3	37.9
VACAR	63,165	82,353	10,824	23.3	32.2
SPP	36,104	57,480	10,489	37.2	46.9
WECC	123,817	169,164	5,638	26.8	29.2
AZ-NM-SNV	23,641	38,857	0	39.2	39.2
CA-MX US	43,544	58,624	4,617	25.7	31.3
NWPP	45,658	57,764	828	21.0	22.1
RMPA	11,815	11,552	194	-2.3	-0.6
Total-United States	**735,065**	**992,147**	**101,832**	**25.9**	**32.8**
Canada					
MRO	7,632	10,026	100	23.9	24.6
NPCC	66,132	83,718	1,633	21.0	21.7
Maritimes	6,297	6,945	758	9.3	18.3
Ontario	22,602	34,410	0	34.3	34.3
Quebec	37,233	42,363	875	12.1	12.1
WECC	25,188	27,852	1,125	9.6	13.1
Total-Canada	**98,952**	**121,596**	**2,858**	**18.6**	**19.9**
Mexico					
WECC CA-MX Mex	2,529	2,811	0	10.0	10.0
Total-NERC	**836,546**	**1,116,554**	**104,690**	**25.1**	**31.5**

Notes for Tables 3a through 3f

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 2009.

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 non-coincident 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.

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. subregion peaks 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 typically 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.

Scenario Analyses Development for 2008

To prepare for and support the *2008 Long-Term Reliability Assessment*, NERC is developing two critical scenarios. These initial explorations are outlined below to provide a baseline of information that will be built upon to create specific, detailed "what if" scenarios for the 2008 assessment. In future years, this process will be expanded and will involve analysis from the regional entities. Much of the background for these scenarios can be found in the *Emerging Issues* section of this report. The two scenarios considered are:

- A Generation Fuel Mix Re-Defined by Federal CO_2 Legislation
- An Industry Facing New Levels of Natural Gas Demand

Scenario 1: A Generation Fuel Mix Re-Defined by Federal CO_2 Legislation

One of the key new findings presented in this assessment report is the industry's increased interest in providing infrastructure to support a resource mix (generation, transmission, and demand-side) affected by climate change regulation. Analysis[33] conducted by the U.S. Department of Energy's (DOE) Energy Information Administration (EIA) of current proposals from the U.S. federal government (cap-and-trade[34], carbon tax, renewable mandates[35], etc.), the Ontario Power Authority, and others, forecasts the following generation fuel mix changes to meet CO_2 goals:

- Reduction of existing coal resources (i.e., Canada)
- Proposed coal plant additions in the U.S.
- Higher reliance on
    - nuclear
    - renewable energy sources (most notably, wind)
- Increased demand-side management opportunities

The EIA analysis of a bill introduced by Senators Joseph Lieberman and John McCain (S. 280)[36] projects an increase in nuclear generating capacity from the current level of 100 GW to 245 GW by 2030, or an increase of 145 GW. If unrestrained nuclear unit construction is not supported in areas seeking increased non-emitting generation, biomass fuels could be a candidate for new generation, especially in those areas where wind and solar power are not available. Additional study by the National Gas Council[37] indicates that if unrestrained construction of nuclear plants

[33] http://www.eia.doe.gov/oiaf/service_rpts.htm
[34] http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf(2007)04.pdf
[35] http://www.eia.doe.gov/oiaf/servicerpt/prps/pdf/sroiaf(2007)03.pdf
[36] *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007,* issued July 2007 by EIA; Report #: SR-OIAF/2007-04
[37] http://www.ngsa.org/docs/GHG_NEMS_FINAL_Report_9-28.pdf

was not possible, and biomass is not fully deployable, higher levels of natural gas fired generation might result (see *Scenario 2*). Further, given the uncertainty associated with foreign gas supplies even with LNG terminal construction and the environmental limits that affect unconventional gas production, new conventional sources of natural gas should be developed.

A significant change in resource mix affects bulk power system reliability. This scenario investigates the impact of increasing three specific technologies: wind, demand-response and nuclear.

Penetration of Wind Energy — Wind generation is projected to become a significant portion of the generation mix. The technology has matured and can enable generation owner/operators to meet federal, state and provincial renewable energy mandates.

The intermittent nature of wind constitutes the major challenge to planning and operating bulk power systems with large amounts of wind generation. Wind generation's total capacity is not available at full output throughout the day and is unavailable most often mid-day when the peak internal demand occurs. In the 2007–2016 timeframe, wind is projected to serve three percent of peak demand. Therefore, to offset the impact of the intermittent nature of wind resources, higher planning/operation capacity margins are required to include supplemental generation (quick-start, gas-fired, or increasingly flexible and dispatchable base-load units) providing load and wind-following flexibility.

Considerable bulk power system upgrades and design modifications are required to provide the ancillary services to deliver new wind energy and to support overall operational reliability, including:

- Load following, frequency response, voltage regulation, and other ancillary services
- Increased reactive support accommodating remotely located wind resources.

High Integration of Demand Response — Demand response is increasingly viewed as an important option to meet the growing electricity requirements in North America, while at the same time addressing green-house gas and CO_2 legislation. Demand response supports operational and long-term planning margins. According to a recent FERC report[38], demand response and the advanced metering programs that enable it have grown significantly over the past year. The report notes major demand response developments in wholesale markets, including its use in forward-capacity markets and ancillary services markets, as well as the development of new reliability-based demand response programs. Demand response lowered the consumption of electricity by 1.4 percent to 4.1 percent during periods of peak demand on the system in 2006, the report states.

A significant amount of demand response resources may reduce the need for planning and operating generation capacity margins, increases bulk power system flexibility, reduces the impact of fuel supply and delivery interruptions, and can be used to enhance renewable integration. Certainty of their availability is vital to ensure demand response provides verifiable reliability benefits. Further, it brings the user of electricity closer to the

[38] FERC Staff Report, *Assessment of demand Response and Advanced Metering*, September 2007, http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf

marketplace. Just like supply alternatives, careful planning is required to support its integration and ensure reliable operation.

Large Nuclear Unit Integration — New nuclear unit designs have significantly increased capacity over older designs (up to 1,600 MW versus 600–1,000 MW). This increased single unit capacity impacts both planning and operational reserves as the sudden unavailability (forced outage) of large units can reduce reliability to a greater extent than smaller units. Additional supply and/or demand-side resources may be needed to support planning reserve requirements, while for operations, increased hot-start and spinning reserve resources (supply or demand-side) might be required to support the reliability requirements of the bulk power system.

Nuclear units are base-load units and traditionally not load following (cycling, starting/stopping, etc.) Though this flexibility may be increasing somewhat with advanced designs, they are generally considered base-load. Significantly increasing the number of the newly designed units may reduce the overall flexibility of the bulk power system, and therefore, its future design would need to accommodate resources that support load-following requirements. Significant bulk transmission system reinforcements would also be required to ensure reliable integration.

Conclusion — To accommodate a shift in resource allocation resulting from CO_2 legislation, the bulk power system will require changes in system design, operating margins and ancillary service requirements to maintain reliability. Furthermore, to manage the expected high integration of demand response, the predictability of these resources must be better understood to ensure that the bulk power system design reliably captures their potential benefits.

Scenario 2: An Industry Facing New Levels of Natural Gas Demand

Natural gas generation, because of its relative ease-of-siting, lower construction costs, and comparative lower CO_2 emissions continues to be a popular fossil-fuel throughout North America, representing up to 19 percent of capacity in the U.S. in 2007. A study by the National Gas Council[39] indicates that if unrestrained construction of nuclear plants was not possible to meet federal CO_2 legislation, and biomass is not fully deployable, higher levels of natural gas fired generation might be needed.

Federal or local environmental policies may encourage the construction of natural gas-fueled generation, and investors as well as Load Serving Entities are attracted to natural gas plants, for these same reasons. However, increased dependency on a single fuel supply increases vulnerabilities in two areas.

Supply — There may be insufficient supply available to support natural gas demand. Domestic consumption of natural gas continues to rise, and is expected to take up much of the domestically available natural gas. Yet domestic natural gas supplies are not increasing. Natural gas imports into the U.S. from Canada are expected to level off and begin declining in 2010, as Canadian domestic consumption increases. Liquefied natural gas (LNG) imports from around the world are

[39] http://www.ngsa.org/docs/GHG_NEMS_FINAL_Report_9-28.pdf

expected to increase, off-setting the decline of the domestic natural gas supply. But LNG requires substantial investment in terminals that convert the LNG into natural gas. If construction of these LNG terminals is delayed, it will impact the nation's ability to rely more on LNG imports to meet natural gas supply needs.

Delivery — Without firm commitments to pipeline owners from suppliers, new pipeline construction cannot proceed as FERC looks upon the degree to which capacity is contracted firm as an indicator of need for capacity. Operators of natural gas-fired generation tend to sign limited firm fuel transportation contracts (release-firm) that have low contractual rights to natural gas pipeline and storage capacity.

Conclusion —- To ensure reliability, federal and state/provincial authorities should support industry efforts aimed at diversifying fuel sources and mitigating risks: increased natural gas storage, dual fuel capability addition, LNG terminal construction, and increased firm contracts for gas supply and delivery. Increased construction of transmission lines could also be part of the solution by facilitating the delivery of power to areas where the potential for gas supply/pipeline disruptions exists.

2007 Long-Term Emerging Issues

Introduction

The balance between the various supply, demand and transmission options that make up the North American bulk power system changes over time. Operation of the system is influenced by a variety of factors and elements, some of which drive reliability higher and others that drive it lower. As a result, planning and operating the reliable grid upon which North Americans rely, on a minute-by-minute basis, requires constant attention and adaptation to keep the lights on today, *and* tomorrow. The *2007 Long-Term Emerging Issues* section was created this year for the first time to probe more deeply into important trends and issues that influence grid reliability, in an attempt to bring together data and news on these trends, and provide a foundation for further discussion and exploration by industry, government and the general public. Going forward, NERC will assess or measure the trends of these forces in conjunction with NERC stakeholders, and recommend appropriate actions that will support increased reliability.

Figure 1 illustrates conceptually the balancing of the aforementioned issues along with the emerging industry issues covered in this document.

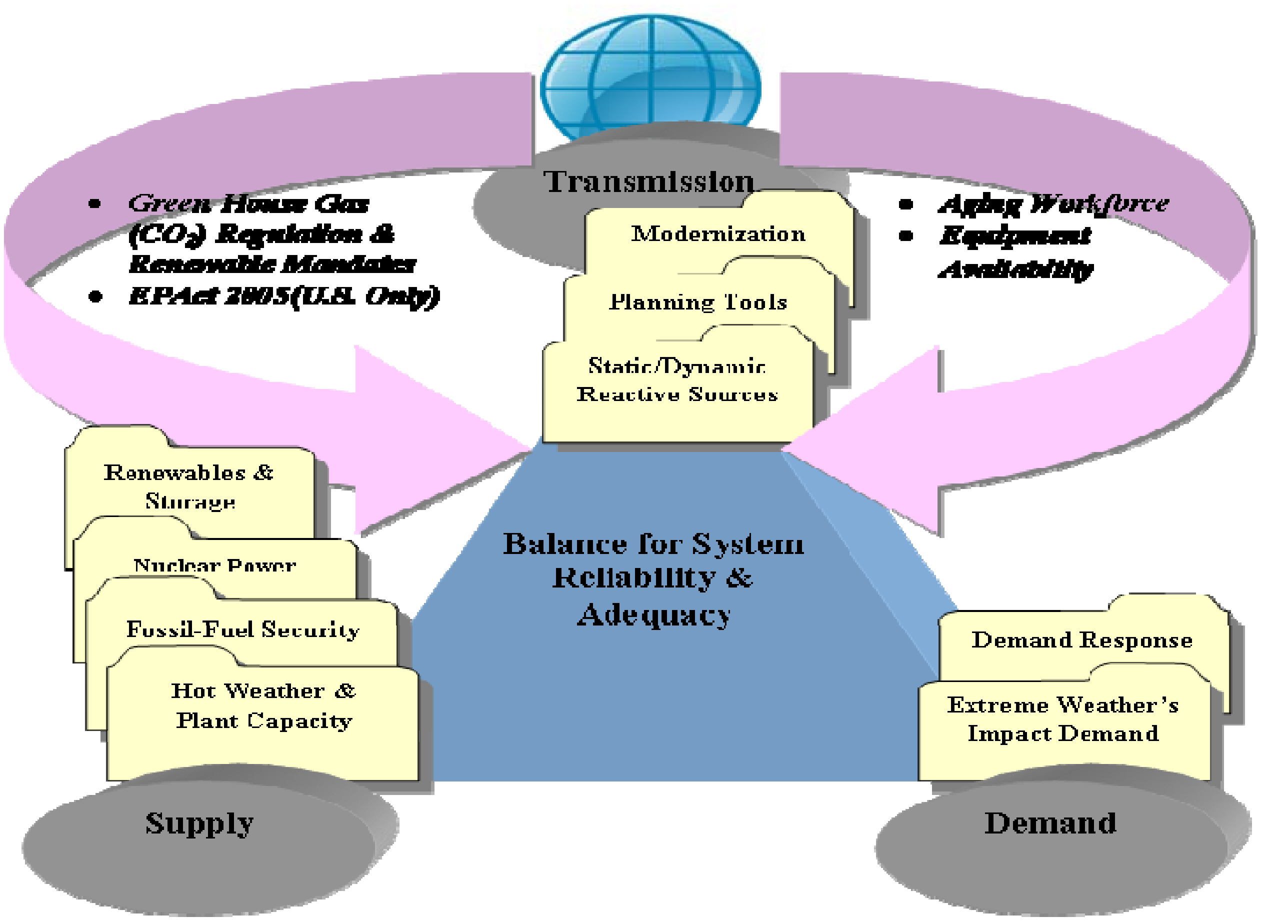


Figure 1: Long-Term Reliability Assessment Emerging Issues

From the analysis of industry emerging issues and input from industry, including a 2007 Open Long-Term Reliability Assessment Workshop, NERC determined the following are vital issues:

Regulatory and Business Issues:

1. **Green House Gas (CO_2) Regulation and Renewable Mandates —** Individual states and provinces are setting renewable resource mandates to address CO_2 emission concerns. Non-emitting generation like wind, solar, and nuclear is on the rise. However, the intermittent nature of the renewables requires new integration techniques and adequate new transmission.
2. **EPAct 2005 — Transmission Related Provisions (U.S. Only) —** The DOE National Interest Electric Transmission Corridors (NIETC) and other transmission-related provisions of EPAct are creating change.
3. **Aging Workforce —** A "perfect storm" of retiring line-workers, supervisors, and engineers could hit in ten years time.
4. **Equipment Delays —** Longer procurement times caused by increasing global demand might affect bulk power reliability.

Demand Issues:

1. **Demand Response** — The industry needs to better understand the influence of demand response on reliability.
2. **Extreme Weather's Impact on Demand —** Planned generation reserve levels generally are used by system planners to account for extreme weather and other uncertainties affecting internal demand. However, long-term reliability analysis continues to show decreasing capacity margins along with increasing demand.

Supply Issues:

1. **Large Nuclear units —** Integration of large units should be coupled with infrastructure investments.
2. **Fuel Supply and Delivery —** Fuel security is vital to bulk power system reliability
3. **Extreme Weather's Impact on Fossil-Fuel Plant Capacity —** When weather is extreme, it impacts the total rating and reliability of fossil-fueled plants.
4. **Renewable and Storage Energy Resources —** Achieving the maximum integration of wind and storage requires a suitable transmission infrastructure.
5. **Impact of the EPA's Ruling on the Clean Water Act —** This decision's impact on capacity ratings of existing plants has yet to be seen.

Transmission Issues:

1. **Bulk Transmission Modernization —** Bulk transmission is a vital enabling infrastructure which must be modernized to reliably support the backbone of the 21st century.
2. **Static/Dynamic Reactive Resources —** At the same time as internal demand grows, unit retirements near cities have increased.
3. **Advanced Planning Tools —** With the unpredictability and volatility of powerflows and the need for broader coordination in planning and operations, the modern system will be more complex. Advanced tools that focus on the boundary of stability, rather than single point analysis are needed to provide better planning and operating tools.

Review of Regulatory & Business Issues

Four of the most significant trends or issues influencing bulk power system reliability are explored in this section.

Green House Gas (CO_2) Regulation and Renewable Energy Mandates

The drive to reduce green house gases, including CO_2, is gaining momentum throughout North America. Demand-side options can play a significant role in reducing CO2 emissions, but will not be enough. Supply-side options that meet green house gas regulations need to be explored, including:

- Non-fossil-fuel-based generation (renewables or nuclear power)
- Fossil-fired fuel technologies that can ultimately prevent CO_2 build-up in the atmosphere, or significantly reduce it compared to existing fossil-fired technologies.

Regulations on Green House Gas emissions, notably CO2, are being promulgated by individual states and provinces throughout the U.S. and Canada. Under mandates in 25 states, clean energy, such as wind, solar and biomass, must be up to 30% of a utility's energy portfolio in five to 15 years. In 2003, just ten states had such requirements.

As states and provinces begin adopting varying approaches to green-house gas emission regulation, the prospect grows that both federal governments will become more engaged and nation-wide legislation result. Renewable energy, mostly from wind farms, is expanding 30% a year.[40]

A few examples of state- and provincial-sponsored regulations are:

- California — Bill AB 32 entitled *The Global Warming Solutions Act of 2006* requires a 25 percent cut in the state's greenhouse gas emissions by 2020, to reduce them to 1990 levels. As defined in the bill, "greenhouse gases" include all of the following gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). These are the same gases listed as GHGs in the Kyoto Protocol. Further, as part of rulemaking[41] for Executive Order S-3-05, the California Public Utilities Commission describes a GHG emissions performance standard that would limit the GHG emissions levels for all new utility-owned

[40] http://www.usatoday.com/money/industries/energy/environment/2007-10-03-clean-energy_N.htm

[41] California Public Utilities Commission, Rulemaking 06-04-009, "Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies"

generation and all procurement contracts that exceed three years in length to "no higher than the GHG emissions levels of a combined-cycle natural gas turbine."

- In an effort to reduce green house gases, many states (about 23) are mandating renewable energy levels:

    - Minnesota has mandated 25 percent of the states energy come from renewable sources. All Minnesota utilities except Xcel Energy Inc. would be bound by the 25 percent-by-2025 standard. Xcel, which delivers half of Minnesota's electricity, is mandated by 2020 to meet 30 percent of energy generated by renewable resources
    - New York has a 25 percent mandate by 2013.
    - Colorado is moving toward a standard of 20 percent by 2020.
    - New Jersey has a "20-20" initiative that calls for 20 percent of its electricity to be generated with renewables within 13 years.
    - Prince Edward Island has a target of achieving 15 percent of its electricity from renewables by 2010.
    - Nova Scotia mandated 20 percent of 2013 electricity will be generated by renewable energy — wind, tidal, biomass, solar and hydro.
    - Florida has a 16 percent target by 2020 by a governor's executive order.

For the U.S., a number of additional regional and state activities are being pursued to develop renewable portfolios (Figure 3[42]). Federal legislation is under consideration, including carbon tax, cap-and-trade, and renewable portfolio standards.

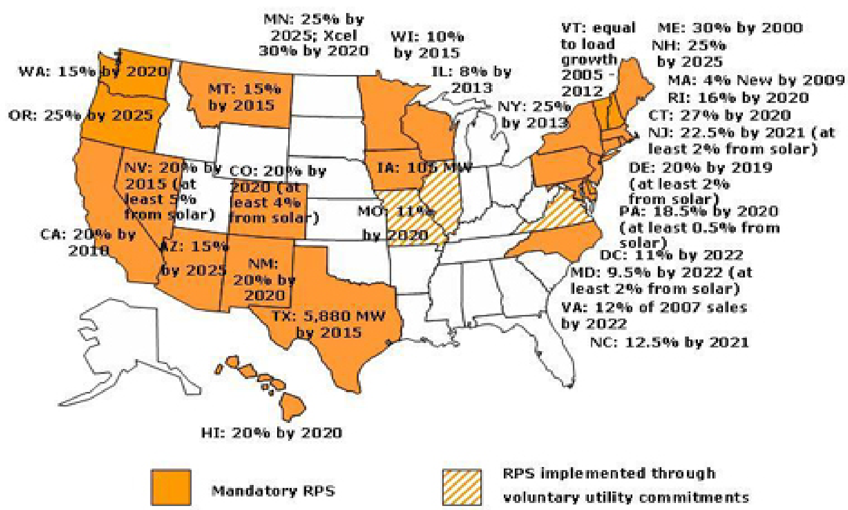


Figure 3: Snapshot of Renewable Portfolio Standards

All of these advancements require intense coordination and integration with the existing system, in order to fully capture their benefits while ensuring system adequacy. These greenhouse gas initiatives can impact the bulk power system in ways including the following.

- Investment risks caused by regulatory variability can delay construction of adequate generation.

---

[42] http://www.pewclimate.org/what_s_being_done/in_the_states/rps.cfm or more detailed resource maps at: http://www.pewclimate.org/what_s_being_done/in_the_states/nrel_renewables_maps.cfm

- Increased investment in Combined Heat and Power (CHP) applications could reduce transmission loading in some areas, thereby improving transmission reliability.

  - Integrating newly sited, non-emitting generation, including small distributed energy projects which serve local loads as well as power the grid, may require construction/upgrading/rejuvenation of the grid.

  - As learned from the recent disturbance in Europe (November 4, 2006), harmonized operations during emergencies is critical to ensure that non-emitting sources are dispatched to support system reliability goals.

  - Large numbers of new generating units replacing retiring plants could temporarily influence system adequacy. Once understood, synchronized action can be taken to ameliorate the effects until balance is realized.

  - If fuel options become limited, energy security and fuel supply vulnerability risks are increased. A balanced fuel-mix must be available to withstand supply disruptions.

  - Generation can become unavailable due to environmental emission limitations impacting system adequacy during years where higher then expected availability of emission-limited units is required. Unavailability of Reliability Must Run (RMR) units can reduce real and reactive power supplies exasperating system conditions.

  - Some non-emitting sources provide energy, but may not be available, at full capacity, to serve peak load requirements, unless coupled with storage technologies. Study of their characteristics can help planners understand how to best site and take advantage of the capacity and develop system/technology strategies increasing their reliability benefits.

Energy Policy Act of 2005: Transmission Related Provisions

Several specific areas of EPACT are intended to improve reliability through enhanced transmission infrastructure siting and enforcement:

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

   Section 1221 of EPAct 2005 requires the Secretary of Energy to publish an electric transmission congestion study 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 FERC backstop authority under certain conditions to preempt state siting processes and approve the siting of transmission facilities within the corridors.

The U.S. DOE congestion study[43], which was published on August 8, 2006, 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.

On October 2, 2007, DOE has designated two NIETCs. The National Corridors are comprised of two geographic areas where consumers are currently adversely affected by transmission capacity constraints or congestion. The proposed Mid-Atlantic Area National Corridor includes counties in Ohio, West Virginia, Pennsylvania, New York, Maryland, Virginia, all of New Jersey, Delaware, and the District of Columbia. The proposed Southwest Area National Corridor includes counties in California and Arizona (Figure 12).

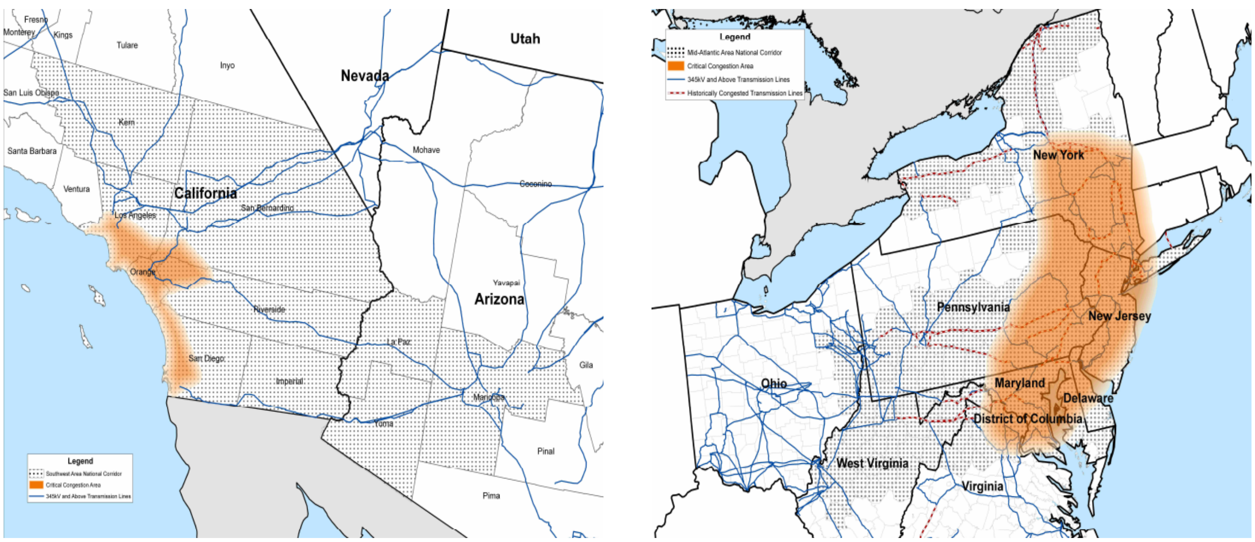


Figure 12[44]: Southwest and Mid-Atlantic Areas, National Interest Electric Transmission Corridors

2. Federal Siting of Electric Transmission Facilities (Section 1221b)

FPA section 1221(b) allows the FERC to issue permits to construct or modify electric transmission facilities in a NIETC under certain circumstances. On June 16, 2006,

[43] U.S. DOE: National Electric Transmission Congestion Study, August 2006
[44] http://www.ferc.gov/industries/electric/indus-act/siting.asp

the FERC issued a NOPR in the "Regulations for filing Applications for Permits to Site Interstate Electric Transmission Facilities" proceeding (RM06-12) and then a Final Rule, Order No. 689 on November 16, 2006.

Order No. 689 lays out the filing requirements and procedures for parties requesting the FERC to use its backup authority to approve the siting of transmission facilities in areas designated as NIETCs. A proposal to build or expand electric transmission facilities must meet several criteria to reduce transmission congestion in interstate commerce, reduce energy independence, and improve energy infrastructure. In addition, the order bars both a formal application and the initiation of pre-filing within one year of initiation of state proceedings to prevent overlapping. In addition, an applicant may pre-file for a federal construction permit which can be submitted in parallel with the state proceedings. Maximum participation from all interested stakeholders is encouraged to disseminate information of the proposed projects, benefits, and environmental impacts.

Once an application is filed, the rule requires public notification of the application, issuance and solicitation of comments on the draft environmental document, preparation and issuance of a final environmental document, a review of the record and issuance of a final decision by the Commission.

3. Coordination of Federal Permits for Transmission (Section 1221h)

This section directs DOE to coordinate all federal authorizations and related environmental reviews needed for siting transmission projects, including NEPA reviews. The purpose of this section is to streamline the process and avoid duplication among federal agencies. An inter-agency MOU has been agreed upon by DOE and eight other federal agencies to guide the coordination process. DOE has delegated to FERC coordination of federal authorizations for siting transmission projects in National Corridors.

The DOE is developing regulations to implement its responsibilities under EPAct section 1221(a) that added section 216(h) to the Federal Power Act. This new section requires the department to coordinate federal authorizations for transmission facilities. DOE will publish its procedural rules in proposed form for comment. In the interim, DOE will be posting information related to federal permitting requirements that may be submitted by transmission developers that would like to be considered for 216(h) treatment once the department's procedural rules are finalized.

DOE is continuing to consider the need for regulations in this area. To the extent the regulations are determined to be necessary, DOE will propose regulations and publish them for public comment. A decision on whether to propose regulations is expected to be made in the near future.

On May 16, 2006, the DOE delegated the authority per paragraphs (2), (3), (4)(A)–(B), and (5) of FPA section 216(h) to the FERC as they apply to proposed facilities in designated NIETCs where an application for authority to construct has been submitted to the FERC.[45]

4. 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 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 are preparing a programmatic environmental impact statement (PEIS) entitled, *Designation of Energy Corridors on Federal Land in the 11 Western States* (DOE/EIS-0386) (see http://corridoreis.anl.gov/guide/maps/index.cfm) to address the environmental impacts from the proposed action and the range of reasonable alternatives. DOE and BLM are 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.

5. Incentive-based rate treatments (Section 1241)

   Section 1241 of EPAct 2005 directed the commission to establish by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce. On July 20, 2006, after considering the comments on the NOPR (issued November 18, 2005), the commission issued Final Rule Order No. 679 that establishes a rebuttable presumption that certain transmission projects approved through a regional transmission planning process, a state siting authority, or located within a NIETC were eligible for incentives. Investment in the transmission system will help ensure the reliability of the bulk power transmission system, reduce the cost of delivered power to customers, and reduce transmission congestion. The final rule does not grant incentives to any public utility but permits an applicant to tailor its proposed incentives to the type of transmission investments being made and to demonstrate that its proposal meets the requirements of section 219. Utilities are not granted incentives automatically. However, on a case-by-case basis, utilities may select and justify the package of incentives needed to support new investments including the use of new cost effective transmission technologies.

   In special cases, developers may recover 100 percent of prudently incurred construction work in progress costs, pre-commercial operation costs, and development costs when a project is abandoned for reasons beyond the developer's control. Transmission owners may be permitted to recover costs necessary to comply

[45] Department of Energy Delegation Order No. 00-004.00A.

with mandatory reliability standards or to facilitate infrastructure development in NIETCs.

The declaratory order/section 205 filing combination allows an applicant to obtain an order indicating that its proposed facility qualifies for incentive-based rates prior to making a formal section 205 filing and actually constructing the facility, which can facilitate financing and investment in new facilities. Once a declaratory order has been issued and the facilities have been constructed, the transmission provider would then be responsible for making the appropriate section 205 filing before any incentive rates become effective.

Based on requests for rehearing and/or clarification of Final Order 679, FERC granted a rehearing on September 19, 2006 and issued its final decision on December 21, 2006. Order 679-A revises/clarifies that in order to create a rebuttable presumption an applicant must meet the Federal Power Act section 219 qualifications for incentive rate treatment and demonstrate that the total package of incentives is tailored to the obvious risks or challenges faced by the applicant in undertaking the project.

The Aging North American Workforce

As highlighted in NERC's *2006 Long-Term Reliability Assessment Report*[46], the industry's aging workforce poses a long-term threat to bulk system reliability. An informal NERC survey of the industry suggests this issue has the highest likelihood and highest severity of all business issues the power industry faces.

The industry is beginning to consider and deploy mitigation strategies. The ultimate goal is ensuring that a pipeline of suitable technical workers will be available to meet the technological and knowledge challenges required to rejuvenate and maintain the bulk power systems of the future.

Specific reasons for this talent scarcity (Figure 4) include:

- Demographics (baby boomers[47] reaching retirement age, reduced birthrate and in the US, lower immigration, etc.),
- Competitive electric power industry market for engineering staff and line-workers[48,49] and/or skilled workers

---

[46] NERC: *2006 Long-Term Reliability Assessment: The Reliability of the Bulk Power Systems in North America,* pages 25–26, October 2006"

[47] Wikipedia: Sometimes called "Baby-Boomers" the term is commonly applied to people with birth years after World War II (WW II) and before the Vietnam War, thus possibly comprising more than one generation.

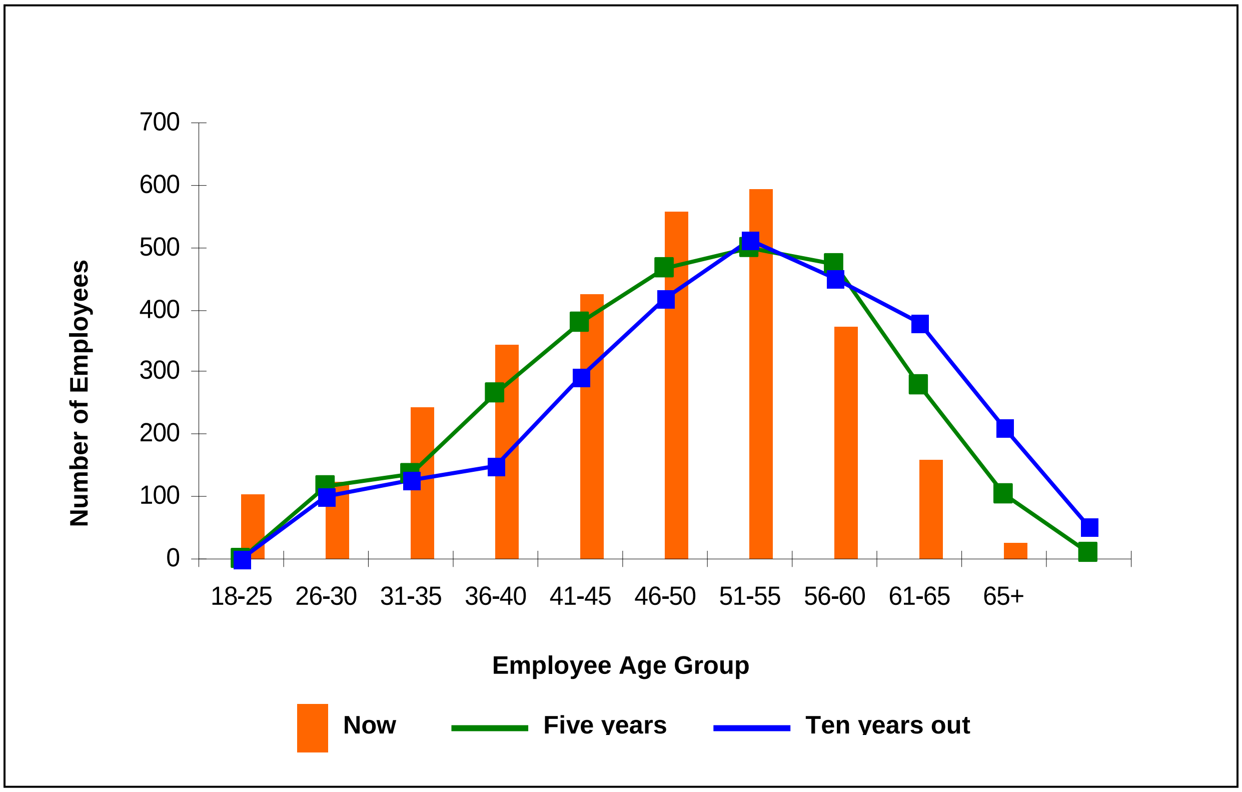
[48] DOE Report: *Workforce Trends in the Electric Utility Industry*, required by Section 1101 of the Energy Policy Act of 2005, http://www.oe.energy.gov/DocumentsandMedia/Workforce_Trends_Report_090706_FINAL.pdf

[49] Deloitte Canada: "Managing Talent Flow: 2006 Energy and Resources, Talent Pulse Survey Report"

- Reduced "head-room" in the electric industry (including manufacturers, vendors, and institutes) pursuing increased productivity has resulted in less hiring/training of new recruits

- Economic risks and maximizing the value of existing assets decreased bulk system construction, which decreased demand for new hires.

As retirements begin in the next ten years, the capacity of the existing power system will be nearing its limits and requiring construction/rejuvenation. A variety of options deploying new technologies need to be weighed to support the expansion of the bulk power system; it's planning, operation, and maintenance will require a substantial increase in workforce.



Source: KEMA

Figure 4: The Aging Utility Workforce[50]

Exacerbating the problem of developing a pipeline of recruits, the reduced demand for industry workers has lead to a decrease in university sponsored electric power programs and vocational training, along with diminished mechanical and chemical engineering coursework focused on the power industry. The industry must court new, suitably talented recruits to shoulder the next round of system rejuvenation.

[50] Ray, Dennis and Bill Snyder. *Strategies to Address the Problem of Exiting Expertise in the Electric Power Industry.* Proceedings of the 39th Annual Hawaii International Conference on System Sciences. January 2006.

A number of surveys are performed annually to review data on workforce demographics. However, to further understand the situation and its solutions, more information is needed on[51]:

- Future labor market demand data
- Hiring trends
- New or emerging occupation skill sets required by the industry

Strategies electric utility companies can take steps including the following:

- Increase the pipeline of recruits
  1. Support organizations focused on workforce development such as:
     a. IEEE-Power Engineering Society's Initiatives[52]
     b. Center for Energy Workforce Development (CEWD)[53]
     c. Human Resources and Social Develop Canada's Electricity Sector Council[54]
  2. Partner with universities and vocational schools to support curriculum that meet industry needs
  3. Provide scholarships to encourage high school graduates to enter the relevant professions.
  4. Band forces with other utilities to promote utility careers. Build regional consortia with other interested organizations.
  5. Encourage governments to support broader immigration to draw on the human capacity outside of North America.
- Modernize the grid with sensors and automation, which will increase bulk power system productivity and mitigate the lack of incoming talent.
- Aggressively capture knowledge from retiring personnel.

Demand for System Equipment is Rising

Manufacturers of power system equipment are running at near full capacity (82 percent)[55], as the demand for equipment required for system rejuvenation has risen dramatically and prices for key commodities, such as copper and steel are increased steeply.[56] Drivers of this increased demand include:

- A number of large countries with growing economies are accelerating the need for materials to support infrastructure expansion.

---

[51] The CIP Report: *An Emerging Issue We Cannot Ignore*, November 2006
[52] http://www.ieee.org/portal/site/pes
[53] http://www.cewd.org/
[54] http://www.tbs-sct.gc.ca/rpp/0607/NRCan-RNCan/nrcan-rncan02_e.asp
[55] National Electrical Manufacturers Association (NEMA), Electroindustry Magazine, December 2006.
[56] NEMA Comments on DOE's NOPR for Distribution Transformer Energy Conservation Standards, Docket No. EE-RM/STD-00-550

- Soaring demand on steel and copper has caused spot scarcity of raw resources required to manufacture key electrical components. This commodity demand has increased the theft of critical system components.
- Manufacturers have attempted to eliminate excess inventories and capacity to increase productivity of their assets. They are reluctant to add more capacity until certain about future industry investments.
- Recent state/provincial commitments to renewable portfolio standards have resulted in substantial increases in wind turbine orders. New wind capacity has been slowed by a worldwide turbine shortage and local opposition to wind projects.[57]

The increasing domestic and global demand for key system electrical components, such as transformers, combustion turbines, and wind turbines, is resulting in potentially longer lead times for procuring these components. For example, lead times to acquire large power transformers have increased by 6–12 months in the past year.

Longer lead times or, even worse, the inability to obtain infrastructure components when needed, influences bulk power system reliability and adequacy. Electric utilities need to plan further ahead to ensure they can acquire needed components to maintain reliability. This planning must balance the need for equipment with the uncertainties/risks associated with forecasts of system requirements.

[57] http://www.usatoday.com/money/industries/energy/environment/2007-10-03-clean-energy_N.htm

Demand Issues

Internal demand or load is a fundamental component of adequacy assessment. Influence of a variety of important emerging parameters are discussed below.

DEMAND RESPONSE

Introduction

Demand response is increasingly viewed as an important option to meet the growing demand for electricity in North America, while at the same time addressing green house gas and CO_2 legislation. Demand response is a subset of the broader category of end-use customer energy solutions known as Demand-Side Management (DSM). In addition to demand response, DSM includes energy efficiency programs. This DSM evaluation is concentrated on the influence of demand response on reliability assessment and; therefore, focused on peak demand reduction rather than overall energy efficiency.

Demand response benefits reliability by reducing customer demand for power, which in turn alleviates somewhat the demand on supply-side and transmission resources. Demand response becomes a resource supplementing reserves, along with operational reliability benefits providing operating reserve and flexibility. Demand response can support the management of operational reserves as well as long-term planning reserves.

Demand response programs require substantial investment in measurement technologies, including advanced metering to enable two-way customer communications, measurement of actual response, and validation of participation. This investment must be recognized along-side other investments as part of overall bulk power system rejuvenation. Increased certainty regarding customer participation, especially for voluntary programs, is required as part of the justification of these investments.

For purposes of this report, NERC will embrace the definition of demand response as proposed by the U.S. Department of Energy in its February 2006 report to Congress[58pp.viii] and adopted by the FERC in its August 2006 *Assessment of Demand Response and Advanced Metering*[59]:

---

[58] FERC Staff August 2006 Report: *Assessment of Demand Response & Advanced Metering* http://www.ferc.gov/legal/staff-reports/demand-response.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp_o=1,100000,0

[59] U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*: A report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006 (February DOE EPAct Report). http://www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf

> *"Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale prices or when system reliability is jeopardized.*

FERC noted that demand response, using this definition, can be divided into two categories: incentive-based demand response and time-based rate programs. Each of these programs has unique aspects influencing the electric utility industry's ability to reliably plan and operate the bulk power system.

The FERC suggests *"The potential immediate reduction in peak electric demand that could be achieved from existing demand resources is between three and seven percent of peak demand in most regions."* This represents a significant resource for meeting demand. Expanding the penetration of these programs or designing new ones may result in an even greater resource impact.

NERC Data

NERC collects two quantities for on-peak megawatts (MW) for seasonal and long-term (ten years) reliability assessment reports: direct control load management and interruptible demand.

As NERC's reports are forward-looking, the remainder of utility DSM programs is captured as part of the internal demand, defined as:

> **Internal Demand**[60]: is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. (Note: integrated hourly demand values are requested.)
>
> *Internal demand includes adjustments for utility indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates***(emphasis added)**. Internal demand should not include stand-by demand and should not be reduced by direct control load management or interruptible demand.

Respondents to NERC's seasonal and long-term reliability assessment data requests modify the demand curve to accommodate a variety of demand response programs (such as time of use, real-time pricing, etc.) which is specifically helpful when forecasting future internal demand. To afford comparative analysis, these

[60] NERC: *Instructions for NERC Summer Assessment Data Reporting*

same quantities are also collected as part of the forecasted seasonal summer/winter reliability assessment data requests.

Demand Response Taxonomy

As the industry's use of demand response changes, NERC's data collection and impact assessment of these programs will change, highlighting those that have an impact on bulk power system reliability. Figure 5 provides a graphic illustration of demand response programs followed by a brief description of the demand response subcategories categorized as described in FERC's report[61].

Where data is collected for NERC's seasonal and long-term reliability assessments, the program description is modified to reflect NERC's nomenclature. Comments are provided on each program's influence on bulk system reliability.

[61] FERC Staff August 2006 Report: *Assessment of Demand Response & Advanced Metering* Chapter IV, Existing Demand Response Programs and Time-Based Rates

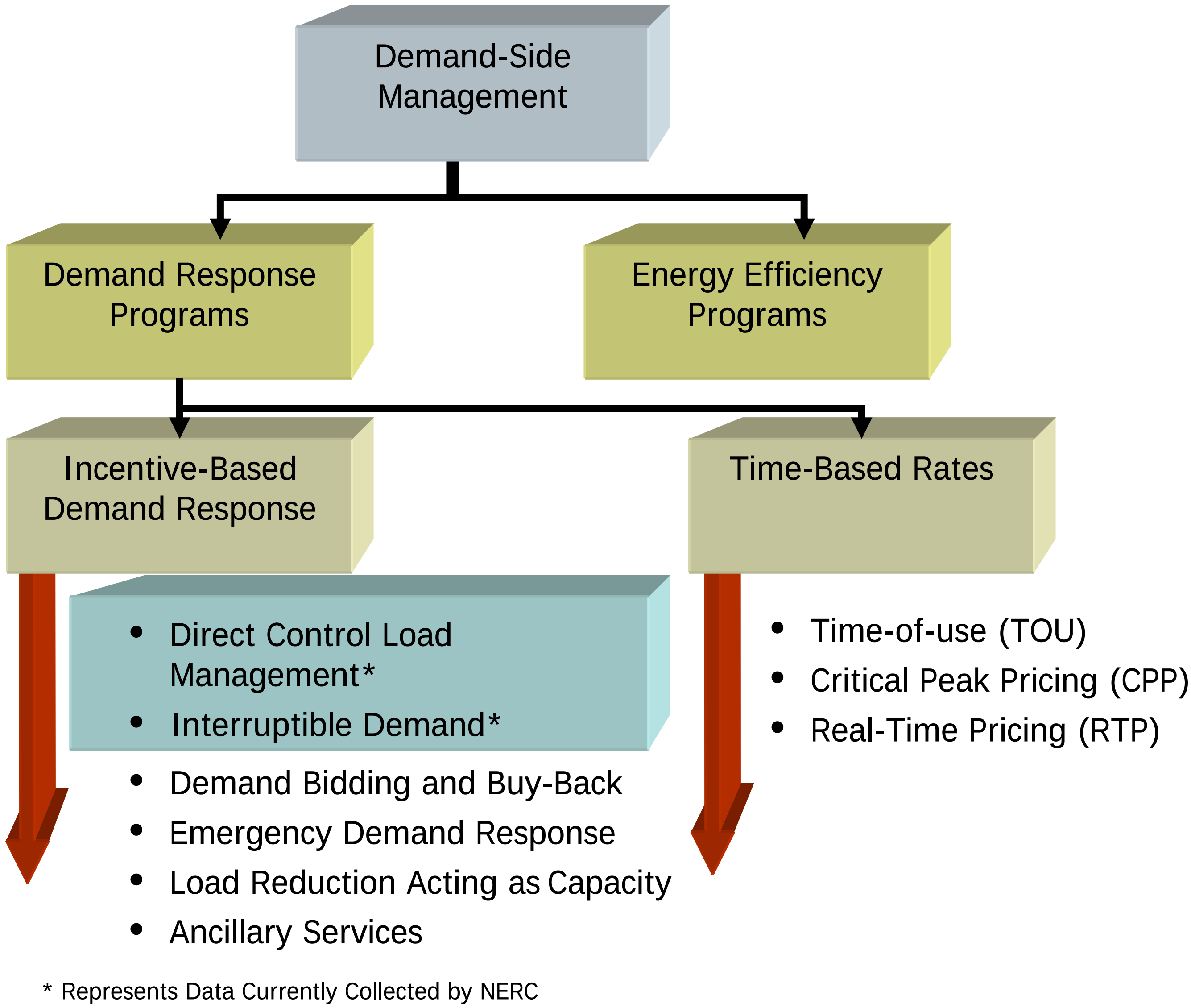


Figure 5: Demand Response Programs and NERC's Data Collection

Data NERC collects on direct control load management and interruptible demand are used to modify the peak internal demand condition. The influence of these programs, which are directly controlled by the operator, is accounted for in the modified internal demand.

As with any demand-side management program, experience is needed to determine program requirements and the expected demand resource available to manage the balance of transmission, supply, and demand. In some cases, the demand response programs are helpful for short-term reliability measures, though unclear in regards to the long-term impacts on reliability. The influence of demand response on this balance and bulk power system reliability requires further study.

Many of the programs are not unique to organized markets and can be applied in most electric utility settings.

Incentive-Based Demand Response Programs

These programs include an inducement or incentive for customer participation and they provide an active tool for load-serving entities, electric utilities, or grid operators to manage their costs and maintain reliability. Some existing incentive-based programs are:

- Direct Control Load Management
- Interruptible Demand
- Demand Bidding/Buyback
- Emergency Demand Response
- Load Reduction Acting as Capacity
- Ancillary-Service Market

Each is described below with their associated reliability benefits.

Direct Control Load Management[62]

Direct control load management refers to programs where the utility or system operator remotely terminates or cycles a customer's equipment on short notice to address system or local reliability contingencies in exchange for an incentive payment or bill credit[63]. These programs have been in place for many years and utilities and system operators have gained sufficient experience to reflect them in both operating procedures and resource plans. The actual benefits vary by customer type, geography and climate. As existing programs are expanded or new programs created, their actual characteristics should be factored into planning and operating activities.

Interruptible Demand[64]

NERC's seasonal and long-term reliability assessments also collect data interruptible demand, defined as:

The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the

[62] NERC: *Instructions for NERC Summer Assessment Data Reporting*
[63] FERC Staff August 2006 Report: *Assessment of Demand Response & Advanced Metering* chapter IV, Existing Demand Response Programs and Time-Based Rates

[64] NERC: *Instructions for NERC Summer Assessment Data Reporting*

Regional Council's seasonal peak by direct control of the system operator or by action of the customer at the direct request of the system operator. In some instances, the demand reduction may be effected by direct action of the system operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as interruptible demand. Interruptible demand does not include direct control load management.

Customers on interruptible demand programs receive a discount or bill credit in exchange for agreeing to reduce load during system events. If customers do not curtail, they can be penalized. Note that interruptible demand programs are different than emergency demand response and load reduction acting as capacity program alternatives as reduction is not always optional. The application of interruptible demand programs is frequently, though not exclusively, used by customers who do not have obligations to provide service (hospitals, schools, etc.) or 24/7 continuous process operations. Though interruptible demand programs have been in place for decades, there is concern about the sustainability and reliability of the resource. For example, the expected participant loss is three percent–five percent each time interruptible demand programs are exercised, influencing long-term assumptions on program participation.

Emergency Demand Response Programs

Emergency demand response programs provide incentives for customers to reduce loads during reliability events, though the curtailment is voluntary. No penalty is assessed if customers do not curtail, and the rates are pre-specified, though no capacity payments are received. This program is typically offered by ISO/RTO, though they are also offered by electric utilities. They are voluntary and part of emergency procedures. Generally, emergency demand response is not included in internal demand data and NERC does not collect this data. Operators can not predict with certainty load curtailment amounts, and planners do not attempt to forecast their influence when developing future system alternatives.

Load Reduction Acting as Capacity

Customers commit to providing specific load reductions during events in return for payments and are penalized if they do not comply. These programs offer a firm, quickly deployed resource (both emergency operating procedure and a mid- to long-term supply option) which can be forecasted for operations and planning. Operating experience is needed to forecast the affect on short-term and long-term bulk power system reliability.

Demand Bidding/Buyback Programs

Demand bidding/buyback programs enable large consumers to offer specific bids or posted prices for specified load reductions. Customers stay at fixed rates, but receive higher payments for load reductions when the wholesale prices are high. There is ongoing discussion to determine which entities should be responsible for paying successful customer bidders. Until this review is complete, it is difficult to determine the operational and planning reliability benefits.

Ancillary Services

In some organizations, these programs are called Load Acting as a Resource (LaaR). Consumers bid load curtailment for operating (i.e. spinning) reserves. Successful bids are paid as standby reserves and if required are paid spot market energy prices to curtail. To participate, customers are pre-qualified having under-frequency relays set by the electric utility, include integral demand recorders and must be able to curtail load quickly when events occur typically in minutes rather than hours. This is juxtaposed to longer duration response for peak-shaving or price signal responses. Ancillary services are focused on operational reliability as a high probability resource, though planners can deploy similar concepts measuring long-term and seasonal reliability when evaluating standard criteria (i.e. N-1, etc.) and reserves. ERCOT considers its LaaR program as an interruptible demand service when determining net internal demand for the NERC LTRA data submittal.

Time-Based Rate Programs

This category of demand response programs, which can link retail and wholesale markets, has recently received a high level of attention. Retail consumers obtain a price signal reflecting the costs of production and delivery which guides them in how to deploy resources more efficiently. This characteristic, as the programs are generally tailored for mass markets, has the potential to reduce or shape electricity use and overall costs. There are three prevalent time-based rate programs:

- Time of Use Rates (TOU)
- Critical Peak Pricing (CPP)
- Real-Time Pricing (RTP)

Time-of-Use Rates (TOU)

The most widespread time-varying program for residential electric consumers, Time-of Use (TOU) demand response are pre-set offerings for a wide variety of time-periods: from seasons to time-of-day depending on the desired application. The pre-set offering reflects the underlying costs for production in hopes that consumers will reduce/curtail their use during the higher priced time-periods. Many utilities now require their larger customers to use TOU demand response. To deploy TOU, investment in meters is required to enable time-stamped billability. Consumers can change their electricity use behavior if price differentials are substantial. There is a multifarious experience with TOU rates with varying levels of success, as results can be hard to predict. Load reduction associated with TOU programs are reflected in actual load recordings and embedded in load forecasts.

Critical Peak Pricing (CPP)

A new form of TOU relies on very high prices during critical peaks rather than average TOU. The offerings are pre-set, but dispatched dynamically on short notice when needed. Data indicates customers do react to reduce/curtail load during the system stress events if appropriate price signals are sent through the CPP. As most proposed CPP programs are currently voluntary, more operating experience is needed. Currently the character of penetration and customer churn rate uncertainty makes it difficult to determine their long-term reliability benefits.

Real-Time Pricing (RTP)

Prices in this program continuously vary reflecting wholesale prices. RTP are not pre-set and are provided hourly and/or day-ahead for pre-planning. RTP provides a direct link between wholesale and retail markets supplying a price-responsive calibration to the electricity market. Further, RTP programs can also enable reduced unit construction as planners and operators can depend on reductions of demand during high-priced hours. As with CPP rates, RTP programs are currently voluntary, again making the impact uncertain until further experience is gained by system operators.

Demand Response Influence on Reliability

There is significant potential for demand reduction to provide reliability benefits as noted in FERC's report[65]. Advanced applications of electricity such as Plug-in Hybrid Electric Vehicles (PHEV), which can act both as a load and mobile storage element (demand and supply), will add new requirements to the bulk power system, as well as offering supportive capacity. Clearly, more load control for planners and operators is required to support the multifarious applications and wisely manage load growth, while at the same time meeting the regulatory requirements promulgated by society.

For example, as demand grows, utilities are beginning to mandate implementation of load control abilities to improve not only the reliability/adequacy of the power system, but also as a first response to large-scale disruptions promulgated by events such as large storms, earthquakes, and terrorist attacks. Many of these events can result in long-term electric disruptions. The ability to differentiate between essential and non-essential demand is critical so utilities can serve essential loads that provide security and health services, while system repairs take place.

It is upon this platform that additional services can be provided to serve reliability concerns, integration of new supply-side options, and economic benefits. In the mean time, more operating and planning experience is needed with demand response programs to fully appreciate their potential and clarify the uncertainty associated with potential reliability benefits. As significant infrastructure investment is required, planners need to understand the scalability of pilot projects reflecting reliability improvements.

Demand response incorporation into resource adequacy assessment should be better understood by the industry. It is important to forecast their growth over the next decade and the influence of customer choice on program participation. In some cases, it may be best to categorize some programs as committed resources, and others as uncommitted. These are key characteristics required to ensure that the reliability benefits can be assessed, and reflected appropriately, without double-counting both as internal demand and potential resource.

IMPACT OF EXTREME WEATHER ON PEAK DEMAND FORECASTS

The behavior of system demand or load is largely correlated to weather. Forecasting system peak demands for the long-term is, therefore, highly dependent on weather-related assumptions, especially the normal temperature and humidity. Normal temperature and humidity are obtained through an averaging process of the last ten to thirty years of temperature data. Other weather conditions such as wind speed, dew

[65] FERC Staff August 2006 Report: *Assessment of Demand Response & Advanced Metering*

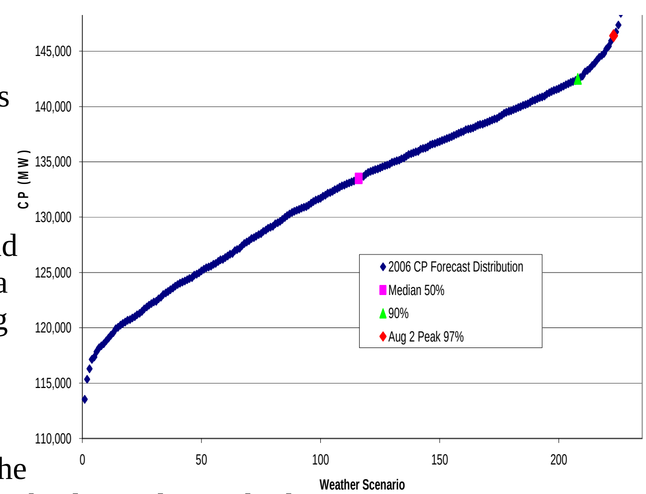
point and cloud cover are also factors, but to a lesser degree. Weather-related attributes affect load characteristics differently depending on the season and class of customer.

The influence of extreme deviations from normal temperature on long-term peak load forecasts is frequently referred to as load sensitivity. Often, at a disaggregated level, residential and commercial customer load is more sensitive to temperature variations than industrial sector load. Extreme weather events, such as temperatures far outside the middle of the forecast statistical distribution curve, can result in a significantly higher forecasted peak load than those derived from normal temperatures. This, correspondingly, affects the adequacy of the bulk power system and is important to consider in sensitivity studies.

Weather Impact on Forecasted Peak Demand

A variety of approaches are used to determine the impact of extreme weather on peak demand forecasts and generation availability. Formal or structured methods include mathematical modeling, probabilistic and weather scenarios. More basic approaches rely on historical statistical analysis, rule-of-thumb calculations, etc. The following are some brief examples in both of these categories:

Figure 6: PJM RTO Coincident Peak Load Forecast Comparison to August 2, 2006 Actual Peak



Formal/Structured Approaches

- Monte Carlo simulation methods used to calculate the peak demand forecast confidence bands
- Load forecast scenarios generated using extreme weather variables
- Load forecast bandwidths generated by a load forecasting model such as a regression model assuming normal temperatures

Basic Approaches

- Historical analysis of the actual load to generate peak demand standard deviations
- Analysis of expected peaks in different temperature ranges to generate the expected peak demand distribution
- Uncertainty factors derived from past occurrences incorporated into forecast assuming normal weather conditions

Planners most often use a 50/50 demand forecast (representing a projection having a 50 percent chance of being exceeded) for reserve margin evaluations. A 90/10 demand forecast (only a ten percent chance of being exceeded) represents the load levels that would occur under extreme weather conditions, and is used for planning purposes as worst case, contingency events.

The 90/10 forecasts representing extreme weather scenarios are used to test the generation, load and transmission beyond their design basis to evaluate the reliability of the bulk power system. Studies include measuring if adequate planned supply-side, demand-side resources, and bulk transmission are available to meet correlated high demand during high temperatures, de-rated generation, and reduced transmission capacity.

These considerations can be significant, and are important to bulk power system operations. As a case in point, the PJM August 2, 2006 peak was the most extreme deviation from the forecasted peak, compared to normal weather, in several years. As mentioned above, generally planners assume a 50/50 forecast. In this case, the peak load of the summer of 2006 was a 97/3 probability load, where 97 percent of the time the peak load will be at or lower than the peak experienced on August 2, 2006. PJM does not permit maintenance over the summer peak period and there were few generators experiencing forced outages at the time of this peak. Therefore, the record peak load was served without incident. Figure 3 graphically illustrates the forecasted versus actual load level.

The temperature in Baltimore, Maryland on August 2, 2006 was 99 degrees Fahrenheit. The normal expected/forecasted high temperature for early August is 86 degrees Fahrenheit. Figure 6 shows that the forecasted load for this extreme weather condition was correctly predicted. While these extreme peak conditions are not common, scenarios are represented in PJM's Loss of Load Expectation calculations, to develop the PJM Reserve Margin requirements.

Extreme Weather Issues

It is common industry practice to use extreme weather scenarios to test worse case scenarios, support operations planning and develop plans to meet any emergencies that result. While extreme weather assessments are important to protect against weather volatility, long-term reserve margin requirements are generally calculated by the industry using normal conditions. Using extreme weather models can lead to overstated long-term demand forecasts and, correspondingly, higher than required long-term capacity reserves. Therefore, reserve margin requirements are based on normal (50/50 load forecast) weather conditions.

Other factors to consider, in addition to the variability due to weather extremes, are the size and diversity of intra- and inter-region load and associated bulk transmission system interconnections. Sharing capacity enabled through interconnection with other systems can be one potential tactic to serve the same peak demand under extreme weather conditions. However, this method assumes sufficient generation availability and load diversity between regions which may not exist if neighboring systems do not have available generation or simultaneously experience extreme weather events reducing the diversity. Also, transmission capacity influenced by both weather conditions and existing flows, affects the potential to transfer energy. Therefore, careful study is required for a variety of scenarios to ensure reliability during extreme weather conditions.

In the long-term, the trend in air-conditioning installations for homes, in states and provinces with slow growth seem to be tapering off. This explains why many parts of North America with high cooling requirements experience high saturation percentages. However, regions experiencing high growth could see an increased weather-related sensitivity of their demand. It is difficult to say which trend will have the largest impact across North America. However, it is likely that weather-sensitive load such as residential class air conditioners could have a lower impact in the future.

Countering this trend in air conditioner saturation is the steady increase in electrical and electronic appliances/equipment found in almost every home. Though there are also offsetting effects from increased energy efficiency of this equipment, new ways to use electricity continue to grow, such as plasma screen televisions and potentially Plug-in Hybrid Electric Vehicles (PHEV). Careful study of the weather sensitivity of the load from this new equipment is required to plan a balance of resources: supply, demand, transmission, and to ensure system reliability.

As planners model and forecast future peak demands, there is significant uncertainty about extrapolating past weather conditions as a consistent prediction of the frequency of future events. A number of advanced models are being developed to include the potential for the higher frequency of extreme weather events, caused by a variety of scenarios. It may be worthy to investigate these scenarios towards planning the appropriate resource balance required to meet weather impacts on load.

Supply Issues

A number of supply issues face the industry, including integration of renewable resources and planned large nuclear plants, fossil fuel availability, and weather impacts on fossil-fired power plant capacity.

INTEGRATION OF RENEWABLES

Almost 50 percent of North American generation relies on fossil-fuels such as coal, oil, and natural gas. Fossil fuels are *nonrenewable*, that is, they draw on finite resources. In contrast, *renewable energy* resources — such as wind, solar, bio-fuels, biomass, hydro, etc. can be replenished at a generally predictable rate, assuming average climate.

As mentioned in the discussion of Green-House Gas (including CO_2 reduction), state/provincial mandates and targets are being set as a way to drive desired reductions in greenhouse gases. Renewable resources quantity and type vary considerably from one geographic location to another. Siting of renewable energy systems therefore requires knowledge of the specific resource characteristics — availability, magnitude, and variability — at any given location. In some cases, especially wind and solar power, these "fuel" concerns emulate those of other generation technologies, though fossil-fuels and biomass can have greater portability and predictability. The lack of portability/predictability of these renewable resources poses greater challenges for the electric delivery system, than generation fueled by other transport systems. Bulk transmission system construction/modernization is a key element to realize the potential reliability benefits of renewable energy resources.

Wind Energy Resources

As wind renewable energy resources are expected to grow substantially (in some locations targeted over 30 percent of overall capacity) throughout North America, understanding how to integrate intermittent resources into the bulk power system and assess their impact on reliability/adequacy becomes increasingly important. In some cases, traditional tools focused solely on capacity, and simplified dynamic models may not be sufficient to gauge that impact.

Around the world, wind generation has become a significant portion of the generation mix. The technology has matured and can enable generation owner/operators to meet federal, state, and provincial renewable energy mandates. The maximum penetration of wind power into a bulk power system before it becomes operationally difficult to control is system dependent. For example, weather patterns of the region, the variety of wind turbine installed, the existing generation mix, and the bulk power system transfer capability with neighboring organizations all influence this saturation limit. The identification of maximum penetration boundaries is system dependent and opaque[66].

Until recently[67], in the province of Alberta[68] of Canada, the Alberta Electric Service Operator temporarily set a "threshold" of 900 MW for wind power production concerned that amounts above that level could destabilize the power grid. With general acceptance of the *Market and Operational Framework for Wind Integration in Alberta* (published March 2007[69]) outlining the rules, obligations and costs of wind integration, this limit was eliminated.

A number of factors are considered when assessing the potential reliability benefits of wind resources:

1. The annual capacity factor of wind generators (the average actual output as a percentage of rated output) is typically about 25–35 percent[70]. The probability that wind generators are available at their rated value during the annual peak period is between 5–20 percent varying greatly from year to year and region to region. Therefore, barring substantial use of storage technologies, wind generation is often considered an energy source rather than a capacity resource.
2. Transmission systems using significant amounts of wind generation must be designed for economical delivery of wind energy and to support a multitude of wind generation patterns. Traditional peak period analysis of transmission requirements does not represent the variable generation patterns modeling all hours of the year. Full year, hourly simulations of generation variations with the transmission systems modeled is required to ensure transmission system designs will deliver the renewable resources when they are available.

   a. Power systems designed to operate when wind resources are not available may deploy demand side management and demand response programs to maintain a reliable system (see section on demand response) on peak. In addition, to maintain system reliability, short term interruption (a few hours) of wind resources may be required. These interruptions will not significantly affect the revenue of a wind generator though State/Provincial Resource Portfolio Standards mandates may result in higher costs of curtailment.
   b. Additional transmission ties to neighboring areas or throughout the region may be required to realize the potential wind resource reliability benefits.

---

[66] CIGRE Technical Brochure, Working Group 601, of Study Committee C4, *Modeling and Dynamic Behavior of Wind Generation as it Relates to Power System Control and Dynamic Performance*, Final Report, January 2007.
[67] http://www.aeso.ca/files/News_Release_Wind_Announcement_-_September_26.pdf
[68] Alberta Electric System Operator, *Incremental Impact on System Operations with Increased Wind Power Penetration*, Final Reports, Phases I & II, November 2005 and July 2006 respectively. http://www.aeso.ca/files/Incremental_Effects_on_System_Operations_with_Increased_Wind_Power_Penetration_rev_2_3.pdf, & http://www.aeso.ca/files/AESO_Phase_II___Wind_Integration_Impact_Studies_final_20060718.pdf
[69] http://www.aeso.ca/files/Wind_Framework_7March07.pdf
[70] EPRI Journal, *Putting Wind on the Grid*, Spring 2006.

3. Increased operating reserve margins may be needed in areas where significant wind resources are located. In addition, market structures can also impact the amount of operating reserves required to mitigate wind output uncertainty.

    a. Transmission should be adequate to provide the import/export capability delivering the system regulation and other transfer schedules required.
    b. Geographic diversity greatly reduces the influence of wind resource variability as short term wind energy variability (less than five minutes) is greater than for longer term (one hour). Sufficient transmission capacity is necessary to manage generation variability over a large area.
    c. The Minnesota Wind Integration Study[71] provides an analysis of the cost of wind integration and the amounts of reserves that must be added to ensure 25 percent of the state's energy is wind energy (40 percent capacity). The state of Minnesota enacted a requirement on February 22, 2007 that requires the states utilities to provide 25 percent of their energy requirements from renewable resources by the year 2025 (see section on Green House Gas Regulation).
    d. Current wind technologies do not follow load variations well. Taking up these variations can be challenging, especially if units fueled by different sources are close to their minimum loading.

4. FERC has developed a breakdown of the various renewable energy initiatives across the U.S.[72]

Solar Energy Resources

Currently less popular than wind resources due to their cost/benefit ratio and capital costs, solar energy resources are also being deployed on the grid. Their variability relates to energy availability when its major fuel supply, the sun, is covered either by dense cloud cover or unavailability at night.

Pacific Gas and Electric Company (PG&E) announced in August 2007 it has agreed to buy power from a 553-megawatt solar thermal power plant to be located in California's Mojave Desert. Solel-MSP-1 plans to build the Mojave Solar Park using its parabolic trough technology, which employs long rows of trough-shaped mirrors that concentrate the sun's heat onto a "receiver" tube. The vacuum-insulated tubing carries a fluid that is heated to high temperatures and is then used to boil water. The steam drives a turbine and generator to produce power. The Solel facility will cover about nine square miles, featuring 1.2 million mirrors and 317 miles of vacuum tubing. When fully operational in 2011, the Mojave Solar Park will produce enough electricity to meet the average annual needs of 400,000 homes in PG&E's service territory. The new contract is the largest solar power agreement in the world.

[71] http://www.puc.state.mn.us/docs/windrpt_vol%201.pdf
[72] http://www.ferc.gov/market-oversight/mkt-electric/overview/2007/elec-ovr-rps.pdf

In recent years, Californian utilities have signed a number of agreements to buy electricity from solar thermal power plants, but none of the new facilities have yet to materialize. Last year, PG&E signed an agreement with another parabolic trough company for 500 MW of solar thermal power. In 2005, PG&E's neighbors to the south — Southern California Edison and the San Diego Gas and Electric Company — signed on for 500 MW and 300 MW of solar thermal power, respectively. Those projects intended to deploy arrays of dish-shaped mirrors that focus sunlight onto Stirling heat engines.

Some experts suggest that a hybrid approach of wind/solar would be a potential solution towards conquering the variability of both towards a more stable renewable supply. Not addressing objections specific to land-use of large scale plant, solar power's scalability from distributed generation and larger power station applications provide infrastructure challenges, especially for bi-directional feeds of the distributed generation alternatives. More information for the U.S. can be found at http://www.nrel.gov/solar/.

Ocean Energy Resources

Ocean energy is categorized into two major types: wave and tidal. These energy systems convert the kinetic energy of moving water into electricity. Mode wave technologies harness the up-and-down motion of water, while tidal technologies exploit energy as the tide moves in and out.

Though a predictable source, the fuel is not as portable as fossil and biomass fuels. Capacity factors are generally assumed to be approximately 15 percent. This technology is currently going through initial, small scale testing throughout the world.

Two turbines have been installed in the East River of New York City on December 2007. One is delivering up to 35 kilowatts of power to New York City. The second turbine delivers performance data crucial to refining the blades and gearbox, generator, and control system to optimize power generation.

Canadian and European tidal-turbine producers are scaling existing designs. For example, a site in Devon, U.K. is operating an 11-meter, 300-kilowatt turbine for four years and plans to install a one-megawatt turbine in Northern Ireland's Strangford Lough this year.

Nova Scotia Power recently agreed to install a one-megawatt ducted turbine in the Bay of Fundy, while another Canadian site off the coast of British Columbia for a two-megawatt unit.[73]

[73] Technology Review, Published by MIT, *Tidal Turbines Help Light Up Manhattan*, April 23, 2007

In the past four years the FERC in Washington, DC, has issued preliminary permits for tidal installations at 25 sites, and it is considering another 31 applications.

Biomass Energy Resources

Biomass-based power generation yields little to no net emissions of CO_2 as the emissions are reabsorbed by plants which then can become fuel. Biomass is currently the largest non-hydro renewable source of electricity in the U.S., used most predominantly in industrial combined heat and power (CHP) applications (especially the paper and pulp industries). Utilities generally use biomass in combination with primary fuels.

Feedstock is portable, but may have limited availability. Investigations into liquid biofuels are currently being performed to increase the portability and intensity of the fuel. Overall, this generation type has many characteristics as central stations, though fuel security needs study. Distributed generation can provide challenges, especially for bi-directional feeds and emergency back-up when biomass plants become unavailable.

Ethanol Production: Internal Demand and Water Use

Ethanol production — much of it from corn predominately in the Midwestern U.S. (See Figure 774) — is increasing, mainly to fuel automobiles. Ethanol production capacity in the U.S. is expected to double by 2009 adding 5,730 million gallons/year (mgy). In modern grain ethanol plants, the critical energy cost is the price of natural gas. During the past year a few plants have integrated coal as a primary boiler fuel. Currently, to dry the grain, natural gas is used to reduce the grain moisture content. Due to the potential for energy price volatility, project developers pay close attention to the selection of process energy sources.

Plant sizes range from roughly 50 mgy to 100 mgy, with approximate electrical requirements of 5 MW to 10 MW, respectively. R&D is being performed to use compressed CO_2 for the drying process, which would double the total required electrical capacity (10 MW to 20 MW respectively). Under construction in the United States are an additional 72 refinement plants75 throughout North America, thus creating internal demand of between 573 MW (5,730 mgy* (10 MW/100 mgy) to 1146 MW (5,730 mgy * (20 MW/100 mgy) spatially dispersed. The load factor for these plants are typically 0.85. Capacity/energy requirements along with appropriate supporting bulk power systems will be required to support this growing industry.

[74] Economist, *The Craze for Maze*, May 10, 2007
[75] http://www.ethanol.org/index.php?id=15

Nearly 95 percent of U.S. ethanol distilleries use natural gas boilers[76]. It is estimated that 28 billion cubic feet of natural gas would be consumed for every one billion gallons of ethanol produced. With the addition of the proposed plants, cumulative ethanol production could surpass 12 billion gallons. These estimates do not include increased fertilizer demand to increase corn yields. It takes about 33,000 cubic feet of natural gas to produce one ton of nitrogen fertilizer. About 96 percent of the corn planted in the U.S. depends on fertilizers, such as Anhydrous Ammonia (NH_3), 28 pct-liquid nitrogen, urea, and ammonium sulfate. Fertilizers consume more than three percent of total U.S. natural gas use. Some 90 percent of the cost of manufacturing nitrogen fertilizer depends upon the price of natural gas.

The more fertilizer produced and ethanol plants, the more natural gas is used and the higher natural gas will eventually cost, assuming adequate pipeline capacity to support these industries. Electric generation plants fueled by natural gas, would face higher prices, and depending on availability of pipeline capacity or natural gas itself, may face potential short-falls in fuel.

Ethanol refinement can also put pressure on water use, with a gallon of ethanol requiring between 2.5–6 gallons[77,78] of water depending on the process (dry-mill versus wet-mill) and vintage of plant. Water reuse has become a standard procedure in most plants today. Wastewater has been minimized and much of the process water is recycled in the plant. In most plants, the only loss of water is boiler blow-down and evaporative loss from cooling towers. Technology innovations are further reducing the total water use at modern plants and reducing the cost of waste stream treatment.

A balanced portfolio of fuel-diverse generation is important to ensure fuel security and over-reliance on any single source can be problematic. Further, integration of these renewable energy resources requires suitable infrastructure.

[76] http://ezinearticles.com/?Ethanol,-Fertilizer-and-Higher-Natural-Gas-Prices&id=551467

[77] Institute for Agriculture and Trade Policy, *Water Use by Ethanol Plants: Potential Challenges* October 2006.
[78] National Academy of Science, "Water Implications of Biofuels Production in the United States, ISBN-13: 978-0-309-11361-8 http://books.nap.edu/catalog.php?record_id=12039#toc, October 2007.

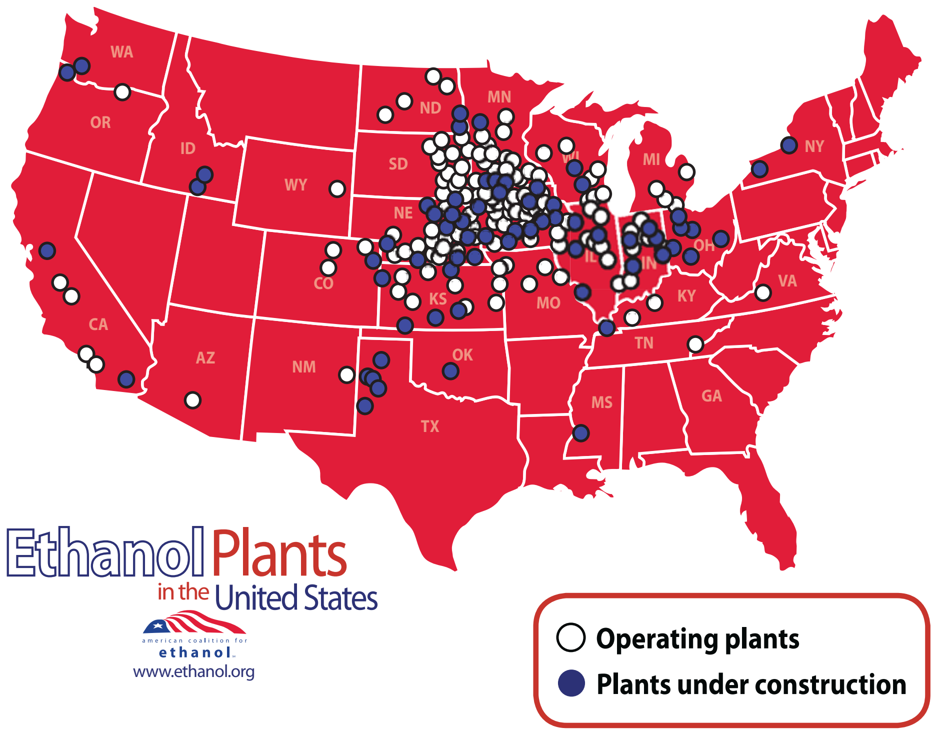


Figure 7: Operating and New Ethanol Refinement plants

Storage Technologies

Prototype storage technologies are being tested throughout North America. Storage can help amplify renewable energy applications smoothing the intermittency of some resources such as wind and solar, making energy available when intermittent resources are not. Further, storage devices can aid in system performance and off-set construction needs, depending on their applications.

For example, sodium-sulfur (NaS) batteries appear to be both compact and long-lasting. A prototype at American Electric Power[79] (1.2 MW) is being tested with another being considered twice this size. Pacific Gas & Electric is reviewing the potential for a five MW version.

Also, compressed air energy storage (CAES), first tested at Alabama Electric Cooperative McIntosh, is being considered in Iowa as a way to store wind energy, by storing compressed air in caverns below ground. When the compressed air is needed for generation, it is mixed with natural gas in a convention gas turbine combustion process to generate electricity. The plant uses off-peak electricity to pump air into the cavern, and then uses the air in the generation process during peak periods. Flywheel technologies are being developed and deployed to supply

[79] USA Today, *New battery packs power punch,* July 5, 2007, pp. 3B.

electricity from a few seconds or minutes to help support ride-through for sensitive loads.

The CIGRE Study Committee C6, "Distribution Systems and Dispersed Generation" has recently initiated a Working Group C6.15, entitled "Electric Energy Storage Systems," to evaluate different storage technologies to support their integration in power systems with high penetration of dispersed generation and renewable based generation.

Geothermal Energy

Deploying thermal energy stored in the earth's crust, geothermal transferred through hot liquids, generally water, and has been used for many years throughout the world. Recent study[80] indicates the amount of hot rocks and fluids contained in sedimentary rock formations in the U.S. are larger and more widely distributed in comparison to hydrocarbon fluids (oil and gas). Geothermal units do not emit CO_2, and can be dispatched as base-load units.

Economically extracting thermal energy may require deep drilling (over two miles) to reach rock temperatures (150 degree centigrade or more) suitable for thermal generation. Improvements required to optimize the use of geothermal energy include drilling, power conversion and reservoir technologies.

With investment in technology[81] development and proactive development, geothermal energy could become a major source of energy (up to ten percent) by 2050.

NUCLEAR POWER IN NORTH AMERICA

Nuclear power has played a significant role in electric power supply for the U.S. and Canada for more than 30 years. Currently, there are 104 operating nuclear power reactors in the U.S. and 22 reactors in Canada. Nuclear power produces approximately 20 percent of the electricity in the U.S. and 13 percent in Canada. The average capacity factor for U.S. nuclear power plants has increased from 70 percent in the early 1990s to almost 90 percent in the early part of this decade. This increase is equivalent to building 25 new 1000 MW power plants.

The North American bulk power system must support existing nuclear plants, including their off-site power requirements, and accommodate new plants. The specific character of nuclear plants necessitates a coordinated approach to their interconnection. Further:

- new plants have been recently proposed,
- sustaining, if appropriate, existing plants through re-licensing,

[80] http://geothermal.inel.gov/what-is.shtml
[81] Idaho National Labs, MIT-led interdisciplinary Panel Report, *The Future of Geothermal Energy*, January 2007, http://geothermal.inel.gov/publications/future_of_geothermal_energy.pdf

- spent nuclear fuel storage restrictions must not reduce production.

Each of these topics is explored below.

New Nuclear Reactor Announcements in North America

Over the past 30 years, nuclear safety has improved, while operational and maintenance costs of nuclear generating units have decreased. Still, no new nuclear power plants have been commissioned in the U.S. or Canada since 1992 (Darlington Nuclear Station, Ontario Canada).

The provisions of the U.S. Energy Policy Act of 2005, broad bipartisan support in recent sessions of U.S. Congress, increased oil and natural gas prices, and societal concerns over greenhouse gas emissions have rekindled interest in nuclear power. These stimulants and the need for generation resources over the next 20 years have resulted in the announcements of a number of new nuclear generators in the U.S. (see Table 1)[82] documented by the Nuclear Energy Institute (NEI) in North America (for the most up-to-date listing for announcements of nuclear units, see[83])

Late last year, Bruce Power, one of Canada's largest power companies, announced they would refurbish two reactors in Ontario that have stood idle for nearly ten years on the eastern shore of Lake Huron.

Company	**Site**	**Design, # of Units**	**Early Site Permit (ESP)**	**Construction / Operating License (COL)**
Alternate Energy Holdings	Bruneau, ID	Not yet determined	-	2008
Amarillo Power	Vicinity of Amarillo, TX	ABWR (2)	Under development, to be submitted 4Q/2007	As soon as practicable after 2007
Constellation (UniStar)	Calvert Cliffs, MD or Nine Mile Point, NY plus three other sites	EPR (5)	Will go to COL but submit siting information early	First submittal 4Q–2007
Detroit Edison	Fermi, MI	Not yet determined	-	2008
Dominion	North Anna, VA	ESBWR (1)	Under review, approval expected 2007	November 2007
Duke	William States Lee, Cherokee County, SC	AP1000 (2)	-	October 2007
Duke	Davie County, NC	Not yet determined	Under consideration	Not yet determined
Duke	Oconee County,	Not yet	Under consideration	Not yet determined

[82] NEI: *New Nuclear Plant Status:* http://www.nei.org/index.asp?catnum=2&catid=344
[83] http://www.nrc.gov/reactors/operating/licensing/power-uprates/approved-applications.html

	SC	determined		
Entergy	River Bend, LA	ESBWR (1)	-	May 2008
Entergy (NuStart)	Grand Gulf, MS	ESBWR (1)	Under review, approval expected 2007	November 2007
Exelon	Clinton, IL	Not yet determined	Under review, approval expected 2007	Not yet determined
Exelon	Texas to be determined, TX	Not yet determined	-	2008
Florida Power & Light	Not yet determined	Not yet determined	-	2009
NRG Energy/STPNOC	Bay City, TX	ABWR (2)	-	Latter part of 2007
Progress Energy	Harris, NC; Levy County, FL	AP1000 (2), Not yet determined (2)	-	Harris — October 2007; Levy County, FL — July 2008
South Carolina Electric & Gas	Summer, SC	AP1000 (2)	-	October 2007
Southern Company	Vogtle, GA	AP1000 (2)	Under review, approval expected early 2009	March 2008
Texas Utilities	Glen Rose, TX Other sites yet to be determined	Not yet determined (2–5)	-	2008
TVA (NuStart)	Bellefonte, AL	AP1000 (2)	-	October 2007

Table 1: New Nuclear Plant Status

Four plant designs have been proposed: Evolutionary Power Reactor (EPR), Advanced Light Water Reactor (ALWR) Program (AP1000), Economic Simplified (sometimes called Enhanced Safety) Boiling Water Reactor (ESBWR), and Advanced Boiling Water Reactor (ABWR). More specifically:

Certified designs[84]:

- Westinghouse AP600
  AP1000
  System 80+
- General Electric Advanced Boiling Water Reactor (ABWR)

Pre-application review by Nuclear Regulatory Commission (NRC):

- Atomic Energy of Canada Limited (AECL) — Advanced CANDU Reactor (ACR) 700
- General Electric — ESBWR
- South Africa — Pebble Bed Modular Reactor (PBMR)

[84] NEI Advanced Certification: http://www.nei.org/index.asp?catnum=2&catid=344

- General Atomics — Gas Turbine-Modular Helium Reactor (GT-MHR)
- Westinghouse — International Reactor Innovative and Secure (IRIS)
- AREVA NP — U.S. Evolutionary Power Reactor (EPR)

Some of these proposed plants are expected to be in operation within the ten-year horizon of this long-term reliability assessment, with others shortly thereafter. When adding new base-load nuclear generation, the specific character of the plant, which can act as a load and synchronous generator when the unit is taken off-line, should be studied by transmission planners and planning coordinators to ensure system reinforcements are also planned. These bulk power system facilities must be built and in-service when nuclear plants go online to ensure a reliable delivery of electricity.

A number of such studies are currently underway, considering announced future nuclear generating units on an individual unit basis and also joint studies to consider the collective affect of several new nuclear generating units located in the same general area, even where the multiple units are located on different power systems. The aforementioned new plant designs have advanced features which minimize off-site power requirements for accident mitigation and, subsequently, the bulk power system support required, excepting the need for some of the plants to run as a synchronous condenser for brief time periods on shut-down. However note that a stable grid is still required to prevent plant trip. Voltage sag or under frequency conditions will cause the main coolant pumps to trip off. Construction of any required transmission facilities and system improvements will ensure that these new generators are interconnected to the bulk power system in a reliable manner.

Reactor License Renewal

The Atomic Energy Act and U.S. Nuclear Regulatory Commission (NRC) regulations limit commercial U.S. power reactor licenses to an initial 40 years. This original 40-year term for reactor licenses was based on economic and antitrust considerations and not on limitations of nuclear technology. The NRC has established a license renewal process with clear requirements that are needed to assure safe plant operation for extended plant life beyond the initial 40 year period. The renewal of licenses for an additional 20 years will be important to ensuring an adequate energy supply for the U.S. into the future. Since 1998, NRC has re-licensed 16 reactors at eight sites in seven states, each for an additional 20 years. 30 more units are under review. NEI estimates that 80 percent of the U.S. fleet of 103 may be re-licensed through 2025.

The first expiration of a commercial power reactor operating license in the U.S. will occur in 2009; the operating licenses for approximately ten percent of nuclear capacity will expire by the end of 2010; and operating licenses for more than 40 percent nuclear capacity will expire by 2015. Since 2000, the U.S. NRC has issued license renewals for 48 nuclear units in the U.S. Another eight license renewals are currently under review by the NRC and the NRC expects applications for license renewal for 30 additional nuclear units in the U.S. in the next six years.

The license renewal process includes two parts:

- Safety vis-à-vis plant aging: The applicant must provide an evaluation of plant aging and explain how it will be managed.
- Environmental impacts: The applicant must provide an evaluation of the potential environmental impact if the plant operates for an additional 20 years.

The NRC reviews the license renewal application and verifies through inspections that the evaluations are valid. The license renewal process can take as much as 30 months if a hearing is required in the process. If a hearing is not required then the license renewal process takes around 22 months.

Existing CANDU (Canada deuterium uranium) plants in Canada can operate economically and reliably with refurbishments, for up to 55 years. All Canadian generators operating CANDU reactors are actively planning on plant refurbishment. As these plants finalize their refurbishments, they will be re-licensed by the Canadian Nuclear Safety Commission (CNSC).

The decision to seek license renewal is strictly voluntary and nuclear power plant owners must decide whether they are likely to satisfy NRC and CSNS requirements and whether license renewal is a cost-effective venture. Should these licenses expire and not be renewed, it will be critical to balanced supply-side, transmission, and demand-side resource replacements to avoid a critical resource shortfall in North America. Further, many nuclear units are being licensed for power up-rates, usually around seven — ten percent range.

Storage of Spent Nuclear Fuel

There are two licensed storage methods for spent nuclear fuel after it is removed from the reactor:

- Spent Fuel Pools — Most spent nuclear fuel is safely stored in specially designed pools at reactor sites around North America.
- Dry Cask — If pool capacity is reached, spent nuclear fuel may be moved to above-ground dry storage casks.

About 160,000 spent fuel assemblies, containing 45,000 tons of spent fuel from nuclear reactors, are currently in storage in the U.S. Of these assemblies, about 156,500 are stored at the site of the nuclear power plant, and approximately 3,500 assemblies are stored at away-from-reactor storage facilities. Over 95 percent of the assemblies are stored in water pools, and the rest are stored in dry casks. About 7,800 used fuel assemblies are taken out of reactors each year. The volume of the 160,000 spent fuel assemblies currently in storage is about equal to that of an American football field — about 5 1/2 yards high[85].

In the US, the DOE is developing plans for a permanent disposal facility for spent fuel from nuclear reactors (as well as for the high-level waste that has been produced by US nuclear weapons production activities). DOE would design, build and operate the facility, subject to federal regulations and oversight by the NRC. The NRC must approve the site/design for the disposal facility, and inspect it during construction and operation.

Canada has produced almost 2 million used fuel bundles – about 36,000 metric tons of uranium – a number which will double if Canada's 22 reactors operate for an average of 40 years each. The fuel bundles from the CANDU reactors are much smaller than the fuel assemblies from US reactors. Canada has designed repositories to permit future recovery of the material should the need arise, while others plan for permanent sequestration.

The Nuclear Waste Management Organization (NWMO) of Canada has recently (2005) completed its initial study on the way forward for dealing with nuclear waste from power plants.[86] The NWMO was established in 2002, formed as a result of the Nuclear Fuel Waste Act (NFWA) to recommend a long-term approach for managing used nuclear fuel produced by Canada's electricity generators. The Government of Canada is reviewing this study and will decide on an appropriate long-term nuclear waste management approach and the NWMO will then implement the approach. A staged approach has been recommended:

- Phase 1: Preparing for Central Used Fuel Management (30 years)
- Phase 2: Central Storage and Technology Demonstration (next 30 years)
- Phase 3: Long-term Containment, Isolation & Monitoring (beyond 60 years)

FOSSIL-FUEL PLANT ISSUES

Over 71 percent of all generation in the United States is fossil-fired[87] and 25 percent in Canada[88]. The electric industry's dependence on generation powered by natural gas has increased significantly (19 percent) and this is expected to continue trough the next 10 years increasing to 22 percent[89]. Long-term fossil fuel transportation interruptions can aggravate system reliability and cause substantial adequacy concerns. Further, de-rates of fossil-fuel plants, due to extreme weather conditions are important considerations

[85] U.S. Nuclear Regulatory Commission: www.nrc.gov/reading-rm/doc-collections/nuregs/brochures/br0216
[86] Nuclear Waste Management Organization (NWMO) of Canada: " Choosing a Way Forward"
[87] Energy Information Administration, "Official Energy Statistics of the U.S. Government"
[88] Centre for Energy, Canada
[89] Energy Information Administration, 2007 Annual Energy Outlook, http://www.eia.doe.gov/oiaf/aeo/pdf/trend_3.pdf

when evaluating the reliability and adequacy of generation and load balance. This section highlights these two issues.

Fossil-Fuel Security

Most of the North American generation is fossil-fuel dependent. Therefore, the ability of the energy sector to meet demand relies on a sufficient and dependable supply of fuel. Security of fuel supply is an important component influencing the reliability of the bulk power system and requires careful consideration/study in assessing overall adequacy. A number of key factors affecting fossil-fuel supply are enumerated below:

- To reduce the cost of maintaining large fuel inventories, generators have changed the way they manage their onsite stockpiles for coal-fired plants, reducing them from 60-days to 30-days. This action can increase the risk and vulnerability to fuel supply disruption. Further, other risks to coal supply exist:

  1. Coal Contracts –Suppliers are either unable or unwilling to fulfill contracts due to spot shortages or higher commodity prices from other purchasers worldwide.
  2. Consolidation in Railroad industry –
     - Capacity of rail lines, and demand for rail stock can cause shortages of rail capacity to meet demand
     - Powder River Basin (PRB) Coal – Roughly 33 percent of U.S. power plant coal consumption is from the PRB[90]. Two railroads have operating rail lines from the PRB area, which may result in rail congestion.
     - Coal consumers captive to a single railroad – generally only one railroad or a short-line railroad under its direct control can deliver coal to the electric generating facility
     - Natural Disasters/Weather – impacts rail and coal production
  3. Labor Issues – Union Contracts/Strikes
  4. Foreign Supply of Coal – Global supply can be disrupted due to political risks in coal production areas and along supply-lines

- Operators of natural gas-fired generation tend to sign up for limited firm fuel transportation contracts (release-firm)[91] which many times have minimal contractual rights to natural gas pipeline and storage capacity. A number of variables can influence natural gas fuel availability and a Load Serving Entities' (LSEs') ability to satisfy resource adequacy requirements:

---

[90] Energy Information Administration, 2004 Coal Distribution Report

[91] Interstate Natural Gas Association of America (INGAA) Foundation: "An Updated Assessment of Pipeline and Storage Infrastructure for the North American Gas Market," F-2004-01, July 2004.

1. Supply versus Demand – There may be insufficient supply available into all regions to support demand (generation, industrial, heating, etc.). Further, Figure 8 shows the current basins in the United States that are unavailable for drilling.[92] For example, EIA projects that natural gas production in Canada will level around 2010 (See Figure 9)[93] with the uptake in Liquefied Natural Gas. Additional study by the National Gas Council[94] indicates that if unrestrained construction of nuclear plants was not possible, and biomass is not fully deployable, higher levels of natural gas fired generation might result. Further, the study indicates given the uncertainty associated with foreign gas supplies even with LNG terminal construction and the environmental limits that affect unconventional gas production, conventional sources of natural gas are needed, perhaps found in the restricted basins.

2. The dependence then on LNG refinement to support natural gas-fired generation is important to understand. Figure 10 identifies the current and projected U.S. LNG refinement terminals. In Canada, two additional LNG terminals are proposed: Rabaska near Quebec City and Cacouna near Rivière-du-loup (east of Quebec City).
   .
3. Competition for Pipeline Capacity[95] – During summer months, much of the pipeline infrastructure must be used to inject gas into storage for the winter months. Summer electric generation requirements compete for space in the pipeline with gas destined for storage injection. The competition will become more intense. Spare seasonal pipeline capacity will not be available unless incremental pipeline infrastructure is constructed.

[92] National Petroleum Council (http://www.npc.org/), "Balancing Natural Gas Policy," September 2003.
[93] http://www.eia.doe.gov/oiaf/aeo/ppt/fig077.ppt
[94] http://www.ngsa.org/docs/GHG_NEMS_FINAL_Report_9-28.pdf
[95] Interstate Natural Gas Association of America (INGAA) Foundation: "An Updated Assessment of Pipeline and Storage Infrastructure for the North American Gas Market," pp. 4, F-2004-01, July 2004.

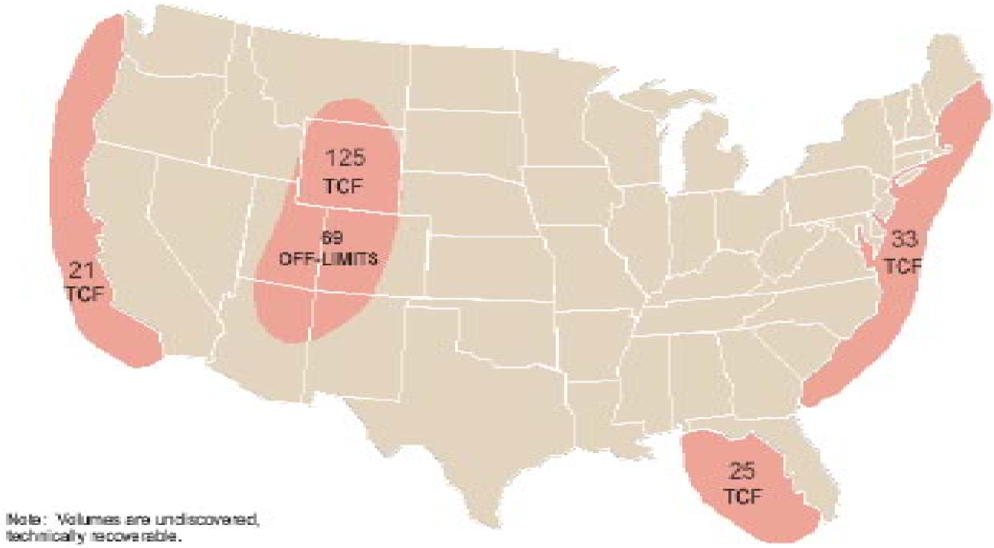


Figure 8: Off-Limits Natural Gas Fields in the United States

4. Long-Term Firm Transportation:[96] The needs of gas-fired power generators for transportation capacity and their willingness to enter into long-term capacity contracts are not always balanced. Gas generators, particularly peaking units, are reluctant to enter into firm, long-term contracts with suppliers. Without firm commitments to pipeline owners from suppliers, new pipeline construction can not proceed. FERC looks upon the degree to which capacity is contracted firm as an indicator of market need.

5. Natural Gas Production Interruption & Gas Storage limitations – gas storage is a limited duration hedge for production interruptions. The proximity of natural gas storage to natural gas production could cause both to be impacted by natural disasters (hurricanes), political uncertainties, terrorist attacks, etc.

6. Foreign Supply of Liquefied Natural Gas (LNG) – Political environments of LNG production areas worldwide and transportation routes are points of vulnerability.

7. The LNG supply is expected to be tight until 2012[97] because of supply constraints at a number of liquefaction facilities, delays in the completion of new liquefaction projects, and rapid growth in global LNG demand.

[96] Interstate Natural Gas Association of America (INGAA) Foundation: "An Updated Assessment of Pipeline and Storage Infrastructure for the North American Gas Market," pp.70-71, F-2004-01, July 2004
[97] Energy Information Administration, Annual Energy Outlook (http://www.eia.doe.gov/oiaf/aeo/pdf/trend_4.pdf)

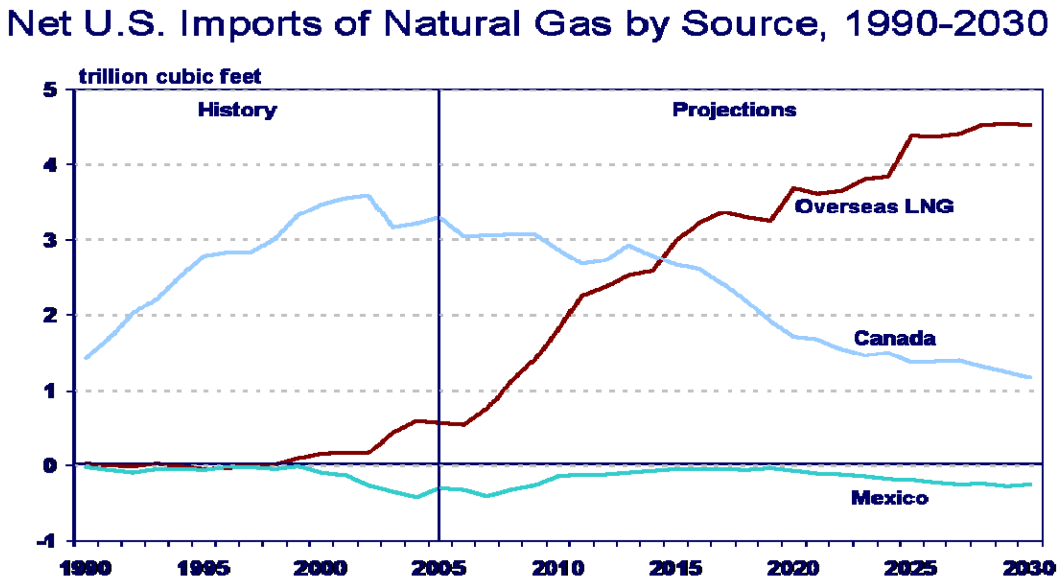


Figure 9[98]: LNG Imports Increasing

8. Outage of Natural Gas Compression Stations – Compression Stations that use electric motors for compression could be curtailed due to natural disasters or electric reliability issues

9. Additional CT & Combined Cycle (CC) plant Fuel Risks are:
   a) Lack of dual fuel capability (oil and gas) of new natural gas fired generation (peaking units and combined cycles): Previously, retail rate based generation projects may have had dual fuel capability; however, today's generation developers attempt to minimize capital costs associated with building this flexibility into new generation projects and supply costs associated with secondary fuel supplies, unless market incentives are available to encourage their capability.
   b) Emissions limitations for running on oil: Emission allowances are exhausted at a faster pace when running generation on oil.
   c) Water availability: Drought conditions can impact CC generation due to the large volume of water that is needed to operate these units. Generation developers can install Dry Condensers; however, these units are less efficient (larger Station Service load) and involve higher capital costs to develop.

[98] [98] Energy Information Administration, Annual Energy Outlook (http://www.eia.doe.gov/oiaf/aeo/pdf/trend_4.pdf)

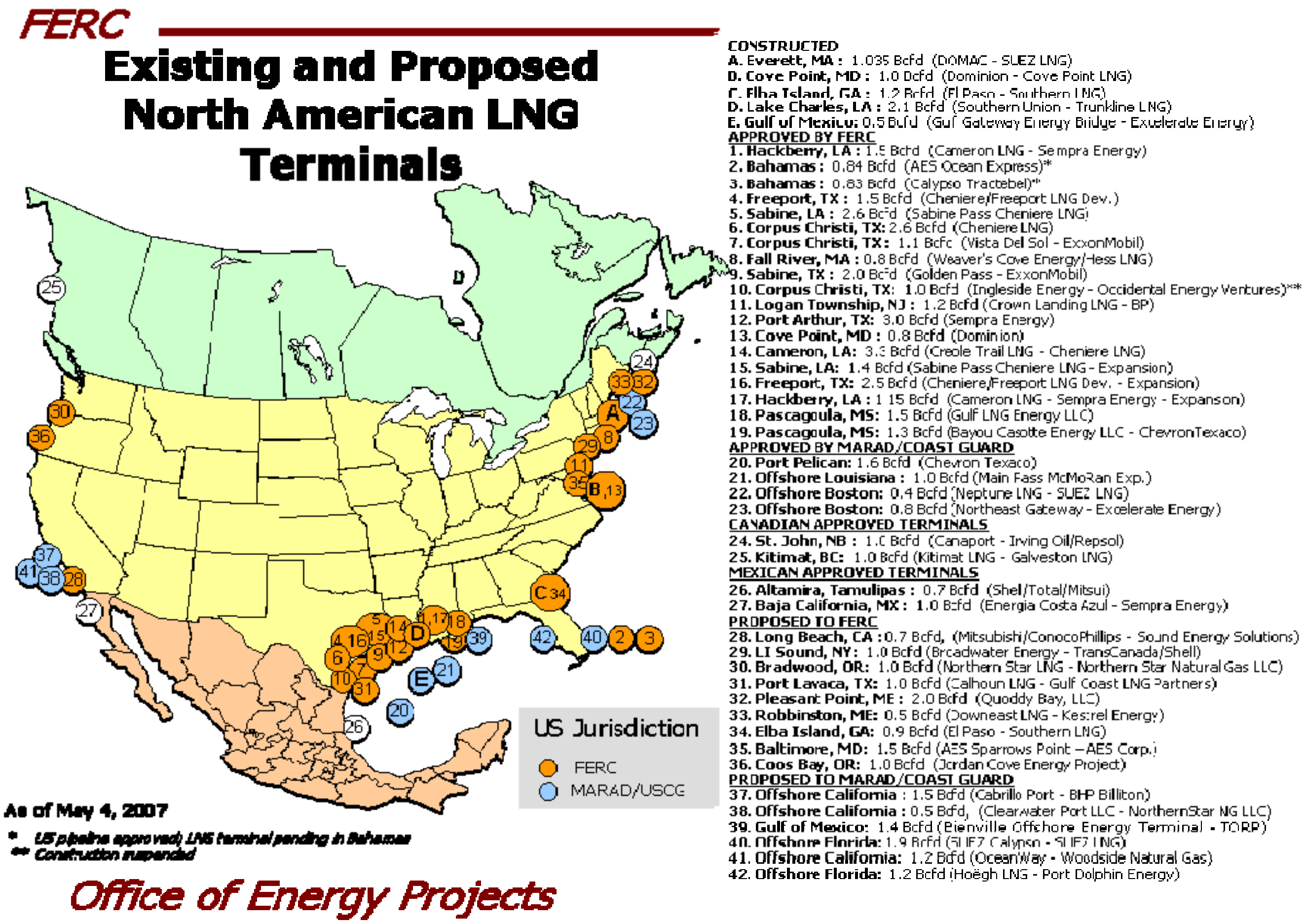


Figure 10[99]: Existing and Proposed North American LNG Terminals

There are also considerable legislative and meteorological influences on security of fuel supply and increase potential risk of vulnerability specific to LNG:

- Federal or local environmental policies, such as the recent regulations promulgated to ban coal-based power purchases by the utilities servicing Californian load[100], may also influence an organization's fuel diversity profile and resulting fuel supply vulnerabilities.
- Both short and long term extreme weather conditions can also result in fuel supply disruptions exasperating imbalances of supply and demand due to correlated weather-related load sensitivity:
    - Prolonged drought affects water availability for cooling of fossil-fired plants leading to plant de-rates, as experienced in Europe last

[99] http://www.ferc.gov/industries/lng/indus-act/terminals/horizon-lng.pdf
[100] California Public Utilities Commission, Rulemaking 06-04-009, "Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies"

year (see Section entitled, "Hot Weather impacts on Fossil-Fired Generation Capacity").
  - During extreme cold conditions, coal piles have been known to freeze, interrupting coal supply to generating plants.

A significant portion of fossil-fired fleets can be vulnerable to various factors leading to regional and local electricity shortages in North America. Some plants are vulnerable based on the character of the specific fuel, meteorological conditions being experienced and the delivery infrastructure. Given time, balanced management of supply-side, bulk transmission and demand-side options can help ameliorate fuel supply risks, taking advantage of regional fuel diversity if required. A strong/diverse supply-side portfolio can help avoid reliance on any single fuel and associated vulnerabilities in fuel supply disruptions.

Hot Weather Impacts on Fossil-Fired Generation Capacity

Sustained extreme weather stresses the system in many ways, not only fossil-fired unit performance, but also line ratings to support reactive flows, higher inductive loads in cities due to air conditioning, and reactive supply issues to support loads in large load centers. Reserve margins and operating procedures are the specific tools utilities deploy to support the bulk power system when it is stressed. For this reason, many regions study extreme weather conditions cases to assure that risks are manageable and acceptable.

Two specific areas are investigated in this section regarding the impact of hot weather on the plant performance: air and water.

Hot Air Impacts on Capacity

Hot air intake, particular gas-fired units, can experience a dramatic decrease in their maximum power ratings during extreme high temperature events. The actual capacity of a combustion turbine generator is de-rated if the temperature exceeds its design specifications[101] (Figure 11 shows an example curve correlating output to temperature). As a result, the maximum output of a combustion turbine generator can be much less than the output that is assumed for normal conditions. For example, a unit with a reported rating of 520 MW at an ambient temperature of 100 degrees Fahrenheit may be limited to 460 MW at 110 degrees and a higher humidity level.

[101] Typical design parameters that determine the maximum rating for a gas fired generator can be for a 104 F Ambient temperature (40 C) at 18 percent humidity. Some of the design parameters can vary by region or manufacturer.

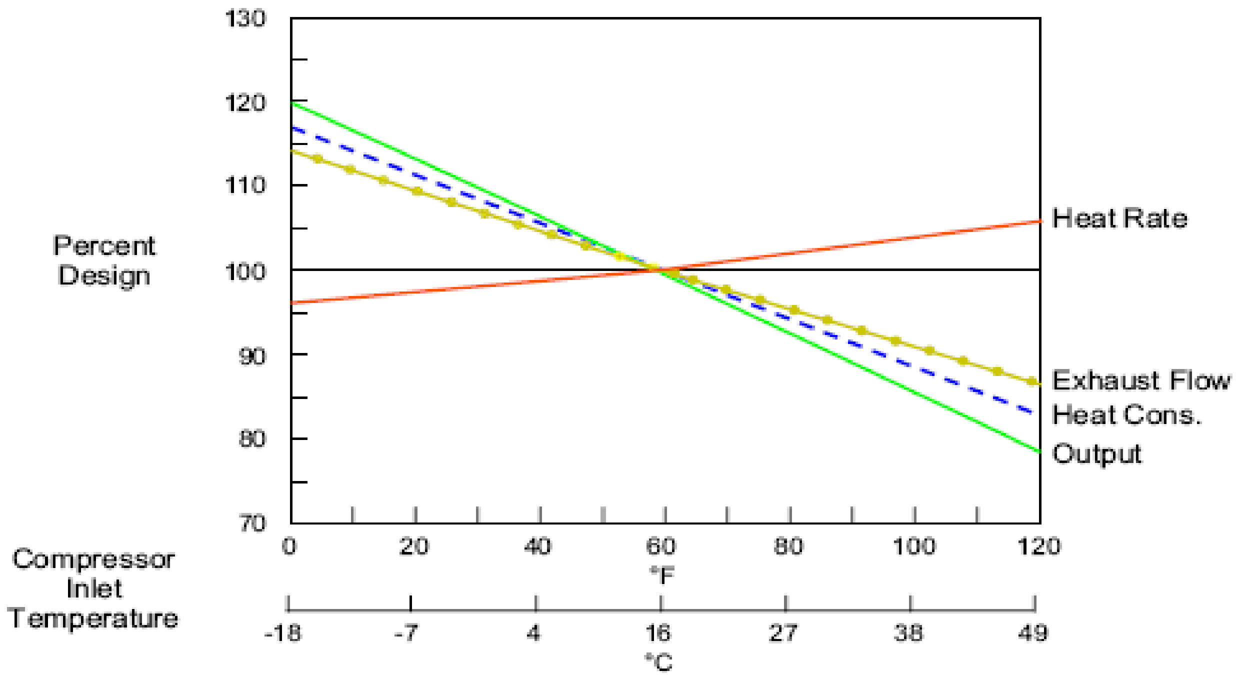


Figure 11[102]: Compressor Inlet Temperature Compared to the Gas Fired Unit Production

These declines in generator output during extreme events are not typically taken into consideration during system assessments based on normal weather conditions. The accumulative effect of many generators with these de-rates can exacerbate expected supply during the extreme regional heat events when generation capacity is needed.

Further, fossil-fired plants tend to experience higher forced outage rates during sustain hot weather. The NERC Generating Availability Data System (GADS) records plant performance and provides statistics validating this occurrence.

Drought & Higher Water Temperature impacts Capacity

After the Summer of 2006's heat storm, close watch on water, and potential drought conditions are being monitored by the industry. Figure 12[103] shows the current conditions based on the National Oceanic and Atmospheric Administrations (NOAA) outlook.

[102] Ms. Chris Veitch of General Electric, Schenectady, NY
[103] http://www.cpc.ncep.noaa.gov/products/expert_assessment/seasonal_drought.html

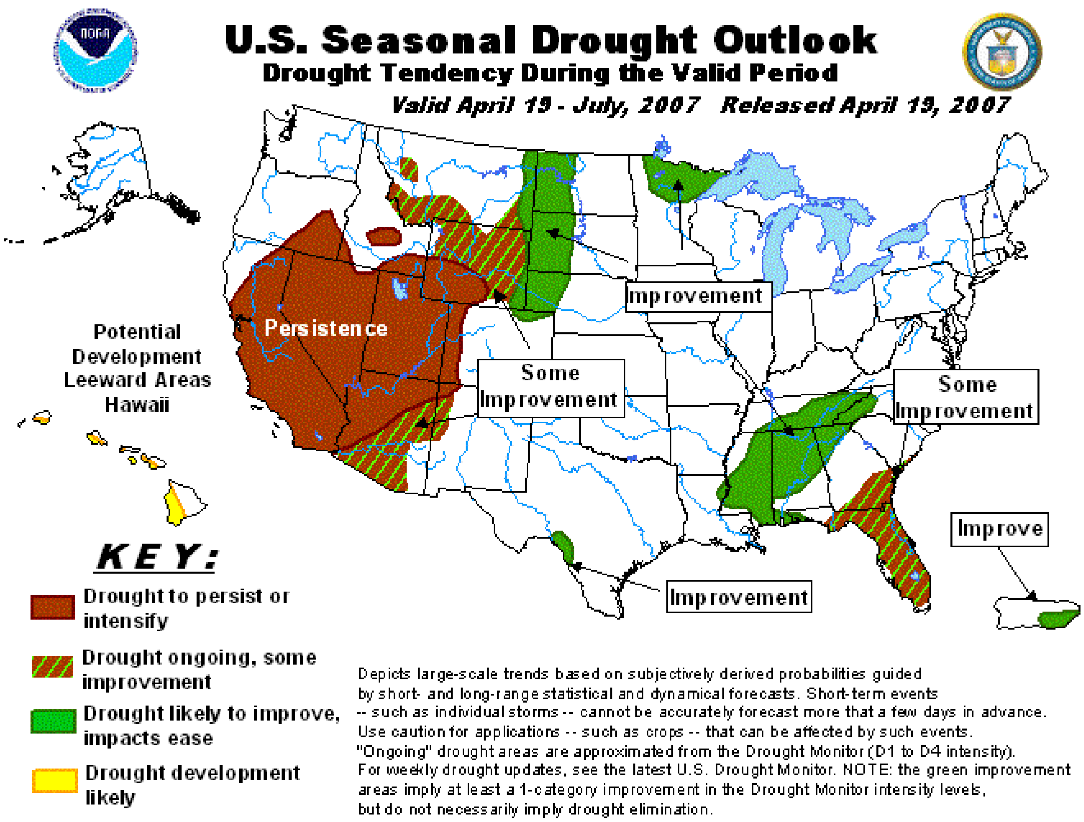


Figure 12: U.S. 2007 Seasonal Drought Outlook

Low water conditions results in pressure on hydro electric capacity and overall water use issues. Industry, including now increased ethanol refinement, along with agriculture, recreation and human water consumption are all part of water management. The power industry requires an adequate supply of water for cooling of power plants, or de-rating could occur.

Further, water temperatures in rivers increase during sustained hot weather. Power plant intake water, therefore, is warmer then expected, and discharge water may be too warm to meet environmental regulations and concerns. Generating units, in this case, may also face de-rating. For example, France and Poland where both faced with this water temperature impact on reliability during the summer of 2006 for both nuclear and fossil-fired plants. Low water and/or warm water limited output due both to environmental considerations and intake fouling due to increase growth of water plants.

In the U.S., for example, according to the Tennessee Valley Authority (TVA)'s water supply manager, TVA has kept the Tennessee River water system at "minimum flows" since February of 2007, cutting normal hydroelectric power generation by nearly 50 percent. In addition, warmer-than-normal reservoirs are threatening to curb or even halt production at nuclear and fossil fuel-fired power plants, which rely on the water supply for component cooling. The Chattanooga area remains in an "exceptional" drought, according to the latest U.S. Drought Monitor report, posted July 17, 2007. According to the National Weather Service, rainfall in the area this year is slightly more than half of normal rainfall.

Regions with weather conditions that can significantly impact the rated output of its internal generation should report this dependency to fully quantify and determine the mitigation necessary to reliably accommodate the impacts of a major heat storm.

Impact of EPA Suspension of Phase II 316(b) Rule

The Section 316(b) provisions of the U.S. Clean Water Act require protection of fish from entrainment or impingement by cooling water intake structures used by industries, including electric generators. The specific language is:

316 (b) Any standard established pursuant to section 301 or section 306 of this Act and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.

Certain groups have sued to have this U.S. EPA rule overturned and were successful. With a current U.S. Federal Appeals Court ruling, most existing electric generating units may be required to be retrofit with cooling towers using more energy and evaporating more water than once through cooling.

The Department of Energy (DOE) has estimated[104] that retrofitting cooling towers to a fossil or nuclear electric generating plant would result in a loss of net generation output of 2.4 to 4.0 percent[105] during summer peak load periods. Considering that there are over 440,000 MW of generating capacity in the U.S. using once-through cooling systems, retrofitting could result in a reduction of nearly 18,000 MW in the U.S., representing a 12 percent reduction in available capacity margin.

Besides the de-rating of existing units, the costs of retro-fitting cooling towers for many older plants may be prohibitive and some may be retired potentially jeopardizing resource adequacy in many regions of the U.S. NERC will evaluate potential impacts on reliability as more information is gained.

[104] http://www.netl.doe.gov/technologies/coalpower/ewr/water/policy/cwis.html
[105] http://www.evs.anl.gov/pub/doc/ANL-SummaryCoolingWaterUse.pdf

Transmission Development Issues

Electric reliability and efficiency are affected by all four segments of the electricity industry: generation, transmission, distribution, and end-use. Investing in only one area will not necessarily stimulate performance improvements across other segments of the integrated system. Increasing supply without improving transmission and distribution infrastructure, for example, may actually lead to more serious reliability concerns.

With respect to electric transmission, reliability is enhanced when additional lines are added to the grid, proper maintenance occurs in a timely manner, and when grid operators are able to make adjustments, in real-time, to address fluctuations in system conditions, particularly during periods of peak demand.

To meet the rising electric power demand, and accommodate the new demand and supply-side options of the 21st century, significant improvements in the bulk power transmission system are necessary. Bottlenecks[106] or congestion of the bulk transmission system worsen system adequacy. Price discrepancies due to congestion provide a form of early-warning signal that reliability problems are on the horizon; these economic signals indicate that, unless a supply/demand imbalance exists or is developing. Unless corrected, this imbalance will compromise the systems ability to reliably supply electricity during peak periods.

Power system behavior continues to challenge existing tools for developing appropriate solutions to meet the challenges of the future. Some of the system behavior requires more detailed analysis and development of new tools to ensure system reliability. Further, as the flexibility of the power system increases, new models of this characteristic are required to increase the potential reliability benefits. These new tools and modeling needs are discussed below supporting emerging issues.

Grid Modernization

Transmission is a key enabling infrastructure of a reliable bulk power system, and its modernization is vital to the system of the future[107]. The addition of sensor and other PMU equipment can be deployed to better monitor power system and equipment for remote action or maintenance. As lines and substation equipment rejuvenation have become an important issue, the integration of maintenance and development activities becomes an important approach to rejuvenate the aging infrastructure. Deploying advanced technologies as part of this rejuvenation can increase system operational efficiency and reliability. This modernization requires not only new technologies, but also new planning models and new techniques for integrating new resources.

[106] Maryland Public Service Commission's report, "ELECTRIC SUPPLY ADEQUACY REPORT OF 2007" January 2007
[107] U.S. Department of Energy: National Electric Delivery Technologies Roadmap," January 2004

Planning: The engineering, design, licensing, and construction of a major high-voltage transmission project require at least 7 years and can extend beyond 10 years. Forecasts of the performance of the bulk power system beyond 5 years are heavily influenced by the addition and location of new generation, dispatch patterns, load growth, and loop flows from other systems. Many times, the actual siting of generation is in flux for years, making transmission development problematic. These uncertainties and risks hamper the ability to conduct transmission planning, while forcing electric utilities and regulatory authorities to make unpopular licensing and routing decisions based on imperfect information.

Independent generators can build power plants, in some cases, where permits can be obtained with ease and there is access to fuel, water, and other necessary infrastructure. Transmission issues can be an afterthought in this process as transmission is many times viewed as the utilities' obligation. For example, in the Southeast (SERC), a large number of power plants have been built or proposed in areas where there is inadequate transmission. Building new generation in these areas could, therefore, increase congestion on the transmission system.

Tremendous foresight and regulatory fortitude are required to propose large regional and inter-regional transmission projects, even those that have a clear reliability need. Therefore, a critical challenge[108] facing the industry is to re-introduce a planning model that characterized the industry historically; namely, one that reintegrates the generation and transmission system planning perspectives that were once routinely joined by vertically integrated utilities.

Over the past several years, most new transmission has been driven by local load serving and generation interconnection requirements rather than a broader perspective. Investment in new regional and inter-regional transmission facilities face challenges including uncertainty in future system conditions, changing and uncertain regulatory environments, and public opposition to new transmission corridors.

As a result, investment in transmission capacity has not kept pace with electricity demand, having fallen from US$5 billion annually in the late 1970s to an average of just US$3 billion a year in the 1990s, while total generation doubled from 1975 to 2000.

Now, the data demonstrates[109] both integrated companies and stand-alone transmission companies are making increasing investments in transmission. Reversing a trend of declining transmission investment from 1999-2004, annual transmission investment by investor-owned utilities increased 10 percent annually totaling nearly $28 billion over this period (in real dollars). From 2005-2009, data indicates that utilities have invested or are projected to invest $37 billion, a 35 percent

[108] U.S. Department of Energy: National Grid Study, May 2002
[109] Edison Electric Institute: EEI Annual Property & Plant Capital Investment Survey, 2007

increase over the 1999-2004 time period. For 2005[110], which is the latest data available, both investor-owned electric utilities and stand-alone transmission companies invested $6.9 billion in the transmission grid. This represents a 9.5 percent increase over the $6.3 billion invested in 2005.

New Technologies: Bulk transmission systems must be designed to integrate advanced technologies. Not only are more bulk transmission lines needed, but new technologies that incorporate intelligent electronic devices (IEDs) and enable smart grid applications are needed as well. These and other technological advancements will help create the flexible transmission grid required to support the dynamic systems of the future – in particular, one in which customers with advanced metering can contribute to load reduction during peaks via demand-side programs. As a most recent example, the American Electric Power Company (AEP) recently announced, if regulatory approvals are received, the integration and deployment of an advanced energy delivery infrastructure and metering technologies focused on enhancing the consumer's ability to control and reduce electricity costs as well as improve the overall efficiency of electricity use[111].

Static/Dynamic Reactive Resources

Adequate static/dynamic reactive power supply is generally maintained through normal planning and operations studies. Managing reactive power effectively in large, interregional power systems improves the use of transmission assets, reduces congestion, and increases power transfer capabilities over the existing infrastructure to meet increased demand.

Reactive power support needs have grown with the steady spread of single-phase air conditioning and other types of inductive motor loads. A number of instances of delayed voltage recovery following clearance of system faults within normal clearing speeds. In 2006, over 37[112] events where experienced in Southern California Edison's (SCE's) system alone.

The duration of these delayed voltage recovery events at SCE ranges from 3 to 38 seconds in 2006. During these events, reduced voltages were observed at all levels on the electrical system, with the lowest voltages observed on the distribution system. The problem appears to be traceable to residential, single-phase air conditioner compressor motors, which tend to stall during a fault, and remain in a stalled condition until tripped on thermal overload. While in a stalled condition, the air conditioner unit draws 3 to 6 times its normal rated current (varying with the voltage of the air conditioner) which results in a sudden increase in load on the electrical grid. The grid continues to serve this load, but this situation adversely impacts the system.

[110] Edison Electric Institute: EEI Electric Transmission Capital Budget & Forecast Survey, 2006
[111] http://money.cnn.com/news/newsfeeds/articles/prnewswire/CLTH02804102007-1.htm
[112] NERC/TVA Stability Workshop, "WECC Load Modeling Transmission Research Program: Overview," Bernie Lesieutre – UW Madison/LBNL, May 24, 2007.

In many cases, the delayed voltage recovery problem self-corrects, and the voltage restore to normal once the stalled air conditioners are disconnected from the distribution either by thermal overload relay on the unit, or by protective relaying on the distribution circuits. However, with increasing number of residential single-phase air conditioners there may be a point with in the ten year planning horizon, when a critical level is reached where voltage recovery may become so severe that a voltage collapse could affect the entire system.

Reactive power[113] does not travel over long distances at high line loadings due to significant losses on the wires. As generation have become increasingly remote from populated areas, planners and operators must balance the need to maintain local voltage support with sources of fast-acting, dynamic reactive sources to counter random grid disturbances. Where reactive support is inadequate, grids are operated with care; many lines are rated well below their full thermal capacity because when grids are stressed, even brief voltage drops caused by transient events (e.g., line outages, plant trips, lightning strikes) can trigger instability and collapse. Figure 14 provides illustration of the impact.

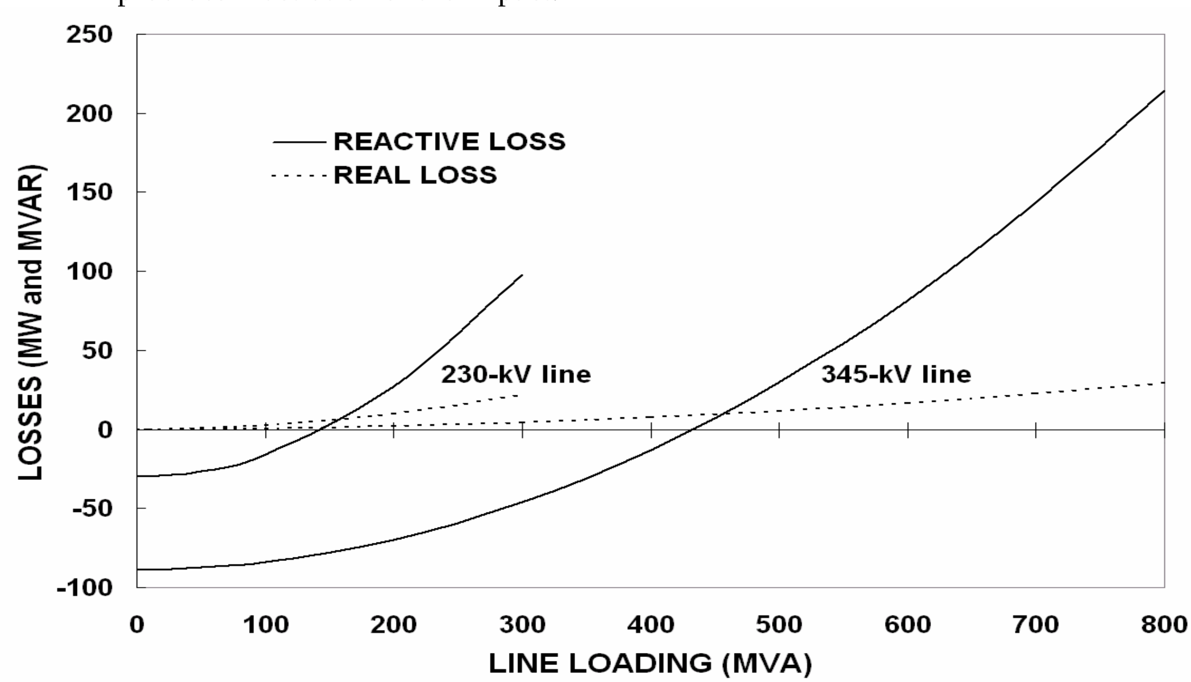


Figure 14[114] Transmission Line Real and Reactive Power Losses vs. Line Loading

A number of equipment alternatives can be used to manage static/dynamic reactive supply:

- Reliability Must Run (RMR) units when their supply is required
- Advanced power electronic devices

[113] FERC Staff Report, “Principles for Efficient and Reliable Reactive Power Supply and Consumption”, Feb. 2005
[114] B. Kirby and E. Hirst 1997, Ancillary-Service Details: Voltage Control, ORNL/ CON-453, Oak Ridge National Laboratory, Oak Ridge, Tenn., December 1997

- Capacitor/inductors
- Enhance end-use equipment to support system voltage recovery. For example, SCE has proposed requiring conditioner manufacturers to install devices that directly trip single-phase air conditioners motors when in a stalled condition.

As extreme weather can be experienced from time-to-time driving loads higher with particular increases in the inductive load from single-phase air conditioners, planners and operators do perform studies on high load, high import cases to determine the adequacy of reactive resources to support static/dynamic voltage requirements. The trend towards remote location of base-load units from load, suggests that a vital part of adequacy assessment is, therefore, the determination of reactive resources. Organizations need to improve their load models periodically through surveys of real time data and system testing to improve dynamic representation enabling enhanced simulation of load impacts on reactive supply.

Planning Tools

Existing tools to measure power system reliability and adequacy may not support the power system of the future. The characteristics of the North American bulk power system are expected to change significantly in the coming years. It is vital that models and tools are available to provide a basis for reliability analysis, both for security and adequacy.

For example, consideration of energy, rather than capacity is becoming more important with the integration of intermittent and demand resources increases. Further, planning the bulk power system using risk analysis, rather than traditional probabilistic and deterministic approaches is becoming more commonplace as industry develops uncertainty characteristics of the bulk power system.

The modern grid must include integration and support for:

1. Intermittent resources
2. Demand response
3. Large deployment of sensor and automation technologies
4. Resources on quick schedules
5. Innovative applications of electricity

Some of the ongoing reliability concerns point to some issues:

1. System transient stability analysis (large signal stability) requires multitudes of scenario calculations. In the end, confidence of the boundary of stability measurement is approximated by this multiple calculations which identify single points along a complex surface.
2. Systems are exhibiting small signal oscillations, some times with no contingencies. Planning tools exist to perform this analysis and for tuning of

power system stabilizers. However, this analysis should fit within the boundary calculations, and currently are carried out, inconsistently, for special cases for control design.

3. Voltage stability analysis, similar to small signal analysis, is performed for special cases, and should also be part of the determination of the boundary of stability.
4. System adequacy has traditionally been calculated using derivatives of the Loss-of-Load Probability (LOLP). This approach falls short when dealing with substantial integration of energy-limited resources.
5. Adequacy is determined regionally, based on many different criteria, approaches and measurements. A consistent, North America-wide calculation of relative adequacy provides equal footing to determine future trends.

It is therefore important that the industry develop:

1. Tools that work towards identification of the boundary of stability (See Figure 15[115]) which identify relative distances to instability, for a multitude of potential events, including large/small signal and voltage stability.
2. Adequacy assessment tools that enable trend, risk analysis and energy analysis based on similar assumptions and for comparative year-on-year analysis.

As the power system is modernized, with increased flexibility and integration of a new fleet of resources and broader application of system control, the existing planning and operating tools will become difficult to deploy, and burdensome. Advanced planning/operating tools, which will support both central and de-centralized control schemes and incorporate the advanced system of the future, will be required.

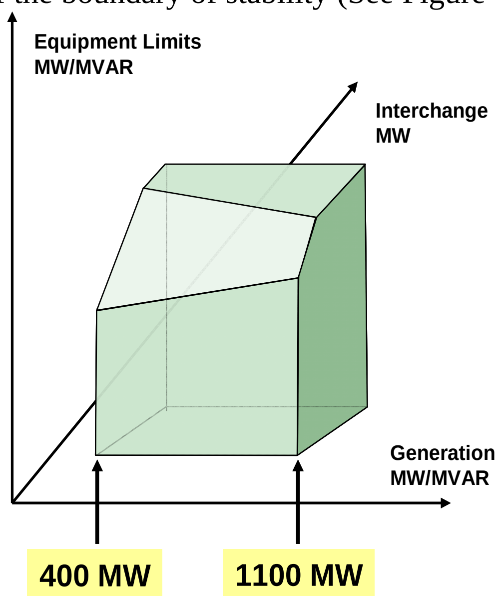


Figure 15 - The boundary conditions are the set of planning or operations planning.

[115] NERC, "Reliability Concepts and Operating Limits concepts," May 2007.

Regional Reliability Self-Assessments

BACKGROUND

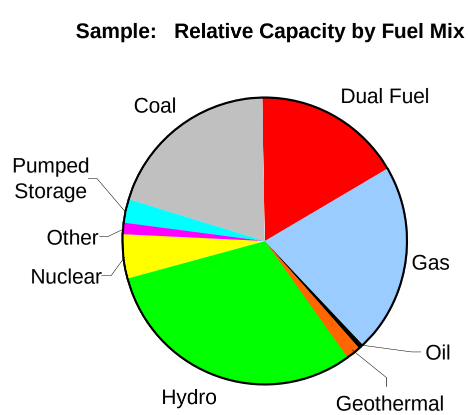
Regional Resource and Demand Projections

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.

Capacity Fuel Mix

The regional capacity fuel mix charts, shown a comparison of percentage between actual regional generating capacity in 2006 and projected in 2012. These fuel charts exemplify each region's relative dependence on various fuels[116] 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.

Sample — Relative Capacity by Fuel Mix



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

ERCOT

Peak Demand and Energy

ERCOT's 2007 long-term peak demand forecast, on the average, is 0.70 percent higher than the forecast produced last year for 2007 to 2015. The key factor driving the higher peak demands in ERCOT is the overall health of the economy, as measured by economic indicators such as the real per capita personal income, population, and various employment measures including financial sector and non-farm employment.

However, the average annual demand growth rate over the assessment period, while still increasing, was reduced from 2.3 percent used last year to 2.12 percent for this year's assessment This year's higher energy demand forecasts are due to an improvement in the economic outlook for Texas. A one time adjustment due to economic revisions and other factors contributed to a 2.40 percent energy demand growth from the actual energy in 2006 to the forecast for 2007. The model was recalibrated to include the effects of having an additional year of historic data, which caused a portion of the forecast to increase as well.

ERCOT's peak demand forecast is 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 generation forced outages (See the "Report on the Capacity, Demand, and Reserves in the ERCOT Region" in the Operations and System Planning Data area of www.ercot.com).

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 forecast using weather and calendar variables. The 90th percentile forecast is about 5.35 percent higher than the median.

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

Currently, ERCOT is adding a new service called Emergency Interruptible Load Service (EILS). EILS is designed to be used in Step 3 of an Emergency Electric Curtailment Plan (EECP) event. The objective is to solicit voluntary firm load that can be shed prior to shedding involuntary load. In return, the voluntary firm load customers will receive a capacity payment. EILS loads would be shed after interruptible load.

The energy forecast from 2007 to 2015 is, on the average, 0.06 percent higher than last year's forecast. The energy growth rate from the 2006 actual energy in GWh to the forecast for 2007 is 2.40 percent. The key factor driving the higher energy consumption is an improvement in the outlook of the overall health of the economy as explained above. The energy consumption is projected to grow at a 2.08 percent over the 2007 to 2017 period. The energy forecast scenarios show a rather slight degree of variability with the 90-10 high weather forecasts projected to be 1.57 percent higher than the median (50-50) base case, and the 10-90 forecast scenarios is projected to be 0.88 percent lower than the median (50-50) base case. The projected energy consumption shows a similar growth as the 1997 to 2006 period (2.09 percent).

Resource Adequacy Assessment

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. This reserve margin should be sufficient to cover, among other uncertainties, the potentially 5.35 percent higher peak demand associated with 90th percentile temperatures. 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 and air permits for fossil-fueled plants
- Switchable capacity to the extent its owners have indicated they intend to be in the ERCOT market
- Based on a recent loss-of-load probability study which includes a determination of the effective load-carrying capability of wind, 8.7 percent of existing wind capacity and future wind capacity with signed interconnection agreements. The "ERCOT Target Reserve Margin Analysis" can be found in the Key Documents section[117]

Generation owners are required to provide ERCOT at least 90 days notice of extended planned shutdowns 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 one remaining plant totaling 169 MW of RMR capacity in the Laredo area 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 by the summer of 2011.

ERCOT has committed resources of approximately 2,100 MW of new fossil-fueled generating capacity with existing signed interconnection agreements expected to come on-line between 2007 and 2012. Almost 2,000 MW of new wind generation is also expected between 2007 and 2012. Last year's assessment reported 672 MW of fossil-fueled generating capacity and 950 MW of new wind generation between 2006 and 2011, all with signed interconnection agreements.

[117] http://www.ercot.com/calendar/2007/01/20070112-GATF.html

A total of 820 MW of DC tie transfer capability exists between ERCOT and SPP and 286 MW of capability between ERCOT and Mexico's Comision Federal de Electricidad (CFE). Entities in ERCOT anticipate importing 191 MW of firm purchases via the SPP DC ties, and entities in SPP own about 200 MW of capacity in ERCOT. These purchases and sales have little impact on ERCOT's ability to meet demand requirements.

The preliminary report of the annual demand forecast indicates the capacity margin will be slightly above the 12.5 percent target for 2008 at 12.6 percent, but declines below the minimum planning reserve margin target beginning in 2009 based on committed resources. Uncommitted resources in ERCOT include mothballed generation capacity and the planned generation that has requested full interconnection studies in the interconnection process. The mothballed capacity is approximately 6,000 MW and could potentially be brought back into service in a short timeframe. By 2016, the uncommitted planned generation is approximately 11,500 MW of non-wind capacity, approximately 14,000 MW of nameplate capacity wind generation and 6,176 MW of nuclear generation.

ERCOT does not foresee any regulatory, deliverability or environmental restrictions that would impact reliability.

Fuel Supply and Delivery

Curtailment of natural gas supply is possible during winter months, which is an issue due to the fact that about 70 percent of the generating capacity in ERCOT is fueled by natural gas. Typically, natural gas supply is not a problem in the summer months due to the absence of heating demand competing for supply. Gas generation currently has no market incentive or non-market mechanism to maintain dual fuel capability and storage, usually 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.

ERCOT has improved communication procedures for Alerts and EECP steps and now sends twice daily system status reports to the PUCT and many others. Alerts and EECP steps are also sent to Legislators, the Governor's office, the State Emergency Operations Center and Board as appropriate depending on the level of concern.

Transmission Assessment

The existing bulk power system within ERCOT is comprised of 38,000 miles of transmission lines, of which 8,515 miles is 345kV. ERCOT, along with its transmission owners' member systems, continues to plan for a reliable bulk power system and plans to add over 1,100 miles of

345-kV lines in the next ten years. Transmission projects that are being considered over the next six years to meet the growing electricity needs are estimated to cost $2.8 billion.

The following major transmission additions (over 600 miles) are projected to be constructed within ERCOT:

Project Title	Projected In-Service Date (Month/Yr)
Collin Switch - NW. Carrollton 345 kV line	Nov-07
Anna Switch - Collin Switch 345 kV line	Dec-07
Hill Country to Skyline 345 kV 2nd circuit	May-09
Spruce to Skyline 345kV 2nd circuit	Jan-10
Hutto Switch - Salado Switch 345 kV line	May-10
Lobo to San Miguel, build 345 kV line	Jun-10
Zorn/Clear Springs-Gilleland Creek-Hutto Switch 345-kV double circuit line	Jun-10
TNP ONE - Bell County SE 345 kV line	Dec-10
Temple Switch - Salado Switch 345 kV line	Dec-10
Trinidad - Watermill 345 kV line	May-11
West Denton - NW Carrollton 345 kV 2nd circuit	May-11
Krum W. 345 kV Switch and Anna Switch - Krum W. Switch 345 kV line	May-11
N Edinburg to Frontera, build 345 kV double circuit line	May-11
Lobo to Rio Bravo 345 kV line	May-11
Venus - Cedar Hill 345 kV line	May-11
Oklaunion to Bowman 345 kV line	Dec-11
Ajo to Cabillo 345 KV line	Dec-11
Cagnon to Hillcountry 345kV 2nd circuit	May-12

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

- Transfers into the Dallas-Fort Worth area from northeast, west 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. 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 Lobo to San Miguel scheduled for service in 2010 will allow termination of the RMR contract in Laredo.

ERCOT develops a 5-Year Plan for the ERCOT area which is based on studies of system performance against ERCOT and NERC reliability standards performed by both ERCOT and individual transmission owners. The results of this analysis are documented in the Annual ERCOT Report on Constraints and Needs. ERCOT also develops a Long-Term System Assessment (LTSA) in even-numbered years which investigates the long-lead-time transmission system improvements that are needed to meet ERCOT and NERC reliability standards through the tenth year of the planning horizon and performs studies in the odd-numbered years to validate that the projects which are included in the LTSA allow the ERCOT System to meet applicable standards. Scenarios including new generation additions (based on uncommitted generation) and mothball returns are included in the transmission needs analysis in order to ensure transmission adequacy in the assessment period.

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

The DC ties with SPP and Comisión Federal de Electricidad (CFE) can be operated at maximum import and export provided there are no area transmission elements out of service. In the event of a transmission outage in the area of these ties, studies will be run during the outage coordination period to identify any import/export limits are needed during the outages. Otherwise, no special studies are done to determine capacity assistance from resources outside of ERCOT.

ERCOT Future Nuclear Generation Publicly Announced and Currently in Study:

- An owner of the South Texas Project (STP) is planning on adding 2,840 MW of additional capacity by 2015, bringing the total plant capacity to 5,404 MW. There are currently nine 345-kV transmission lines into the STP plant. ERCOT's initial assessment concluded that one of the 345-kV lines may need to be upgraded and rebuilt in order to handle the additional capacity.

- An owner of the Comanche Peak plant is planning on adding 3,336 MW of additional capacity by 2015, bringing the total plant capacity to 5,664 MW. There are currently five 345-kV transmission lines into the Comanche Peak plant. ERCOT's initial assessment concluded that a significant number of transmission system improvements would be required to handle the additional capacity, including the possibility of adding three new 345-kV lines.

The next step in the interconnection study process is for ERCOT participants to conduct more detailed transmission studies for the STP and Comanche Peak plants respectively. Such studies will specify the final expansion plan for the new plants to interconnect with ERCOT in compliance with NERC, ERCOT and NRC requirements.

Texas has an abundance of wind resources suitable for wind generation development. A recent study conducted by ERCOT found that there are over 130,000 megawatts of potential wind energy capacity throughout Texas. Through project-specific interconnection agreements, and through the system-wide Regional Planning Group process, ERCOT will work with Transmission Owners (TOs) and stakeholders to design transmission improvements that will both ensure the system meets all applicable reliability requirements and cost-effectively minimize system operational costs.

The Public Utility Commission of Texas (PUCT) has designated new Competitive Renewable Energy Zones and ordered ERCOT to develop transmission plans to incorporate up to approximately 25,000MW of installed wind capacity from these Zones into the ERCOT system (PUCT Docket #33672). This study is scheduled for completion in early 2008. ERCOT has hired an outside consultant to conduct an analysis of the impact of additional wind generation capacity on system ancillary service requirements. This study will include a detailed analysis of the current variability of load in ERCOT and an analysis of the expected changes in this variability as additional wind resources are added to the system. The study will also provide an analysis of the capability of the current generating fleet in ERCOT to provide the levels of ancillary services required due to the expected variability of net load (load minus wind), and an analysis of the likelihood and potential impacts of extreme weather events. This study will be complete by the end of 2007.

Operational Issues

No major facility outages, regulatory restrictions, 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 reserve margins.

On February 24, 2007 ERCOT experienced winds in excess of 29 meters per second in some areas of West Texas, which caused about 1,550 MW of wind generation to trip. The different technologies respond in a variety of ways. Some were able to stay online, while others have the capability to curtail output and some trip. After the tripping and automatic curtailing of wind generation, ERCOT implemented step one of EECP because ERCOT dropped below the EECP trigger of 2,300 MWs of adjusted responsive reserve as reserves were used to replace the reduced wind generation. ERCOT is undertaking a study of the appropriate level of ancillary services that would be necessary to meet the operational requirements in the future due to the increasing amount of wind resources connected to the ERCOT system.

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. ERCOT has recently completed the annual review and modification of RAPs and SPSs. The approval process and statuses of RAPs and SPSs can be found at www.ercot.com in the Operations and System Planning Data section, by clicking on the Special Protection Systems (SPS) Information folder.

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 will have an Operator Training Simulator available in 2007 to train operators on simulated EECP and other unusual events.

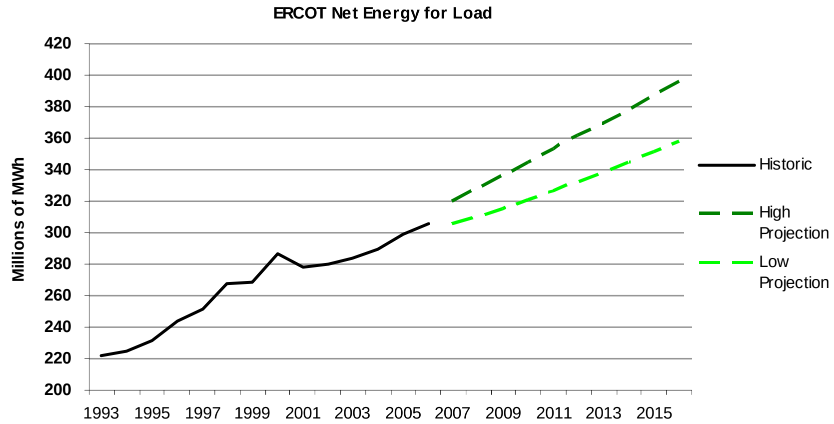
ERCOT operators are able to perform real-time voltage stability analysis. This analysis addresses one of the recommendations from the report on the 2003 blackout.

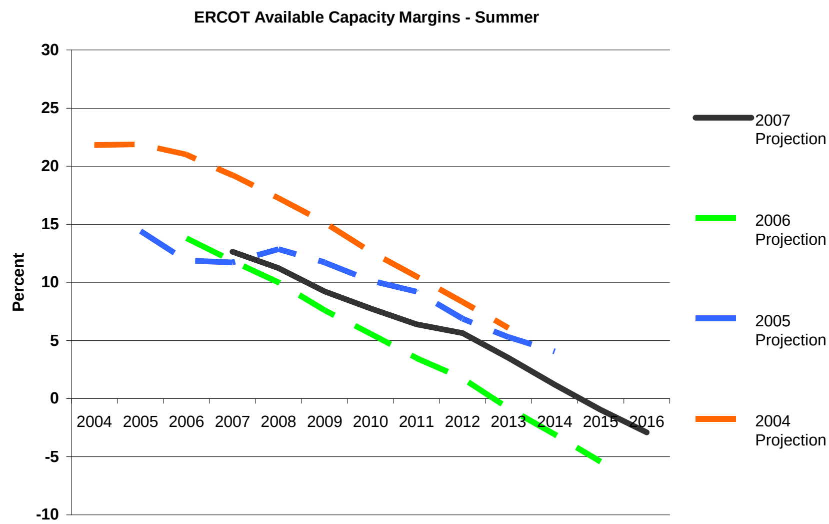
The Public Utility Commission of Texas (PUCT) has approved a major market redesign that would change current congestion management procedures from a zonal to a nodal-based system. This transition, currently scheduled for December 2008, may present challenges in implementing new operating computing systems but should also improve the efficiency of transmission congestion management.

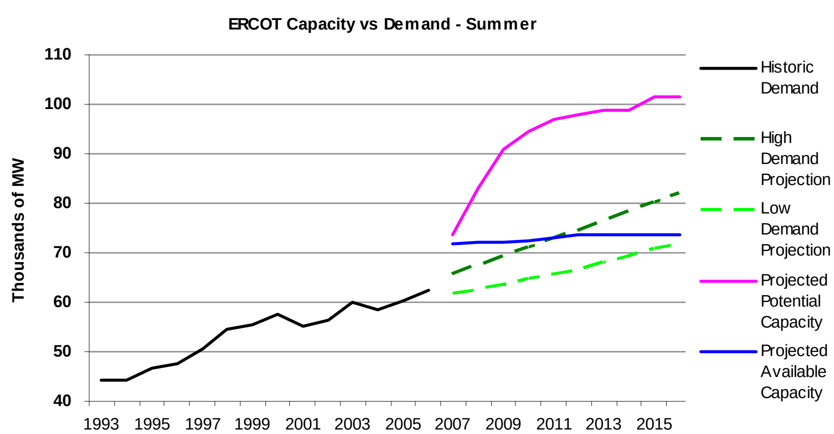
Region Description

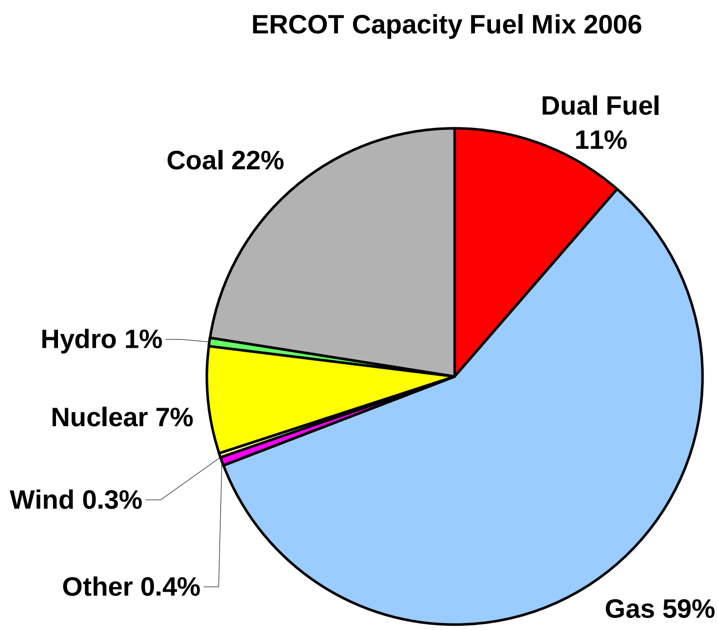
ERCOT is a separate electric interconnection located entirely in the state of Texas and operated as a single balancing authority. ERCOT has 135 members that represent independent retail electric providers; generators, and power marketers; investor-owned, municipal, and cooperative utilities; and retail consumers. It is a summer-peaking region responsible for about 85 percent of the electric load in Texas with a 2006 peak demand of 62,339 megawatts. 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).

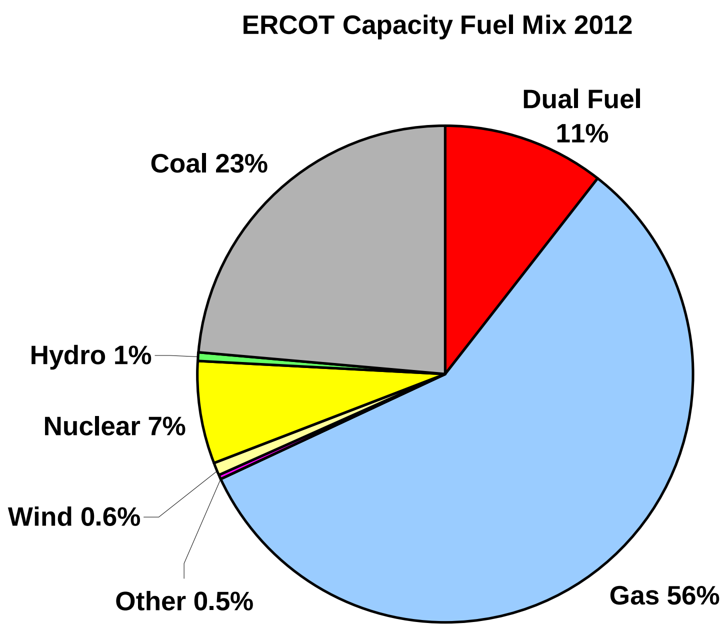
ERCOT Capacity and Demand








ERCOT Capacity Fuel Mix 2006
Dual Fuel 11%
Coal 22%
Hydro 1%
Nuclear 7%
Wind 0.3%
Other 0.4%
Gas 59%


ERCOT Capacity Fuel Mix 2012
Dual Fuel 11%
Coal 23%
Hydro 1%
Nuclear 7%
Wind 0.6%
Other 0.5%
Gas 56%

FRCC

Peak Demand and Energy

FRCC uses historical weather databases consisting of as much as 58 years of data for the weather assumptions used in their forecasting models. Historically, the 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 peak demand in the FRCC region for 2006 was 45,751 MW as compared to a peak demand forecast of 45,520 MW. The 2007 ten year demand forecast for the FRCC region exhibits a compounded average annual growth rate of 2.2 percent over the next ten years compared to last year's compounded average annual growth rate of 2.4 percent. The decrease in peak demand forecast growth rate is attributed to an increase in demand side management participation as well as higher electricity costs and a decrease in economic development in Florida. The 2007 ten year net internal demand forecast includes the effects of 3,702 MW of potential demand reductions from the use of load management (1,792 MW of residential & 1,036 MW of commercial/industrial) and interruptible demand (874 MW) by 2016.

FRCC employs two different techniques to assess the peak demand uncertainty and variability. First, FRCC develops regional bandwidths or 80 percent confidence intervals on the projected demand. The 80 percent confidence intervals on peak demand can be interpreted to mean that there is a 10 percent probability that in any year of the forecast horizon that actual observed load could exceed the high band. Likewise, there is a 10 percent probability that the actual observed load in any year could be less than the low band in the confidence interval. The purpose of developing bandwidths on peak demand is to quantify uncertainties of demand at the regional level. This would include weather and non-weather 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 is incorporated into the simulations. The regional aggregated peak demand for the FRCC is established using these simulations.

The 2007 ten year energy forecast for the FRCC region displayed growth similar to the 2006 forecast. Yearly energy consumption is expected to rise by 2.8 percent over the next decade, exactly matching last year's projected 10-year growth of 2.8 percent. The actual energy consumption for 2006 was 230,115 GWH which is lower than the forecasted value of 232,561 GWH mainly attributed to lower than forecasted summer temperatures.

Resource Adequacy Assessment

The Florida Public Service Commission 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[118] that is produced each year and filed with the Florida Public Service Commission. The FRCC 2007 Load and Resource Plan shows the average FRCC reserve margins over the winter and summer peaks for the next ten years is twenty-three percent (23 percent). All years are well above the 15 percent reserve margin standard established by the FRCC. The calculation of reserve margin includes firm imports into the region and does not include excess merchant generating capacity that is not under a firm contract with a load serving entity.

In the event resource unavailability is higher than expected, resources in the FRCC region are expected to be adequate given the average reserve margin (23 percent) including over 3,000 MW of demand side management which is well above the 15 percent reserve margin criteria for the FRCC Region. Therefore, regional resource adequacy, even with higher resource unavailability, is achieved throughout the FRCC region by having sufficient resources available and the capability to deliver these resources.

FRCC is projecting a net increase (i.e., additions less removals) of 17,991 MW of new installed capacity over the next decade, compared to the 16,617 MW projected by last year's ten-year forecast. Of this net increase, 12,502 MW are designated for gas-fired operation in either simple-cycle or combined-cycle configurations, 4,627 MW[119] are anticipated for coal-fired operation, 1,305 MW designated as new and upgraded nuclear, and 443 MW are related to oil-fired units that have been de-rated and/or retired. Gas-fired generation continues to dominate a high percentage of new generation. It is forecast that electrical energy produced from natural gas generators will increase from 38 percent in 2006 to 44 percent in 2016.

Environmental and regulatory restrictions may have a negative impact on the status of planned coal-fired plants within the FRCC Region. The 2007 10-Year Site Plans include 4,627 MW of proposed coal-fired generation representing 26 percent of the total generation being proposed. If coal-fired plants are delayed or cancelled, it is anticipated that these plants will be replaced with additional gas-fired generation.[119] The FRCC will closely monitor any regulatory and/or policy changes and the utilities' response to ensure that resource adequacy is maintained.

There is 5,062 MW of existing merchant plant capability in the FRCC Region, of which 3,916 MW are under firm contract. The planned construction of merchant plants has decreased significantly over prior year's 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.

[118] The list of existing and planned generation by fuel type can be found in the "2007 Regional Load & Resource Plan" for the FRCC Region.

[119] Of the total 4,627 MW of proposed coal-fired generation, 2,708 MW have been cancelled since this assessment was conducted. Replacement generation plans are being developed.

Currently, there are 1,552 MW of generation owned or under firm contract that are available to be imported into the Region. These firm resources account for about five percent of the Reserve Margin. FRCC utilities own about 858 MW of the 1,552 MW which are dispatched out of the Southern Subregion of SERC. This firm capacity has firm transmission service to ensure deliverability into the FRCC region. There are no firm long-term sales to other regions.

FRCC conducted a Loss-of-Load Probability (LOLP) analysis of peninsular Florida for the 2006 – 2015 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 non-firm imports; and availability of Demand Side Management. The study considered the variability of these factors and their impact on LOLP and concluded the existing and planned resource additions over the coming decade results in a predicted LOLP of less than the 0.1 days per year.

Fuel Supply and Delivery

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

In addition to the short-term fuel assessment coordination processes, the FRCC continues work on a more detailed natural gas pipeline and electric interdependency study process. The FRCC has developed a high-level, transient gas flow model to study and analyze the gas pipeline system and its impact on reliability in peninsular Florida. Additional data related to natural gas usage within the region has been collected, modeled and used to evaluate reliability impacts of gas supply constraints and the mitigation capabilities within the Region. Preliminary study results, based on detail natural gas pipeline models, indicate that potential gas transportation issues can be adequately mitigated by properly dispatching dual fuel units on liquid fuels.

Fuel supplies continue to be adequate for the region and these supplies are not expected to be impacted by extreme weather during peak load conditions. There is no identified fuel availability or supply issues at this time, and no additional mitigation strategies have been developed. Based on current fuel diversity, alternate fuel capability and preliminary study results, the FRCC does not anticipate any fuel transportation issues affecting capability during peak periods and/or extreme weather conditions.

Due to the reliance on natural gas for existing and future generating capacity coupled with the uncertainty of coal-fired plants, the FRCC will monitor closely any regulatory policies related to alternate fuel types that can help improve the fuel diversity within the FRCC Region[21].

Transmission Assessment

The results of the short-term (first five years) study for normal, single and multiple contingency analysis of the FRCC region show that the thermal and voltage violations occurring in Florida are capable of being managed successfully by operator intervention. Such operator intervention can include generation re-dispatch, system reconfiguration; reactive device control and transformer tap adjustments. Major additions or changes to the FRCC transmission system are mostly related to expansion in order to serve new demand and therefore, none of these additions or changes would have a significant impact on the reliability of the transmission system.

Transmission constraints in the Central Florida area may require remedial actions depending on system conditions creating increased west-to-east flow levels across the Central Florida metropolitan load areas. Based on the committed projects and expected generation dispatch, it is expected that these remedial actions will continue in this area through 2010. Permanent solutions consisting of new proposed facilities and the rebuilding of existing facilities have been identified and implementation of these solutions is underway. Some of these proposed facilities include constructing a new 230kV transmission line from West Lake Wales to Intercession City and rebuilding the existing transmission line from West Lake Wales to Intercession City.

The long-range (remaining five years) study results reveal developing thermal and voltage issues in several areas in the FRCC region which the responsible utilities acknowledge would 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 northwest of Lake Okeechobee 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 projects required to meet the long range needs of the transmission system.

Presently there are 1,125 MW of new planned nuclear generation for 2016. The transmission integration expansion plans for this new generator are under study by the transmission owner. Once the interconnection and integration transmission studies are complete the FRCC will evaluate the transmission expansion plan to ensure there are no reliability concerns.

Currently, individual transmission owners plan to construct 719 miles of 230 kV transmission lines during the 2007-2016 planning horizon. The following major transmission additions are planned to be constructed in the FRCC Region:

Proposed Projects (Name)	Proposed In-service Date (Month-YR)
Bobwhite to Manatee 230kV line	Dec-11
St. Johns to Pringle 230kV line	Dec-08
Avalon to Gifford 230 kV Line	Jun-08
Hines to West Lake Wales 230kV #1 line	Dec-07
Hines to West Lake Wales 230kV #2 line	Jun-09
West Lake Wales to Intercession City 230kV #2 line	Jun-20
Greenland to Nocatee 230 kV #1 Line	Dec-11
Greenland to Nocatee 230 kV #2 line	Dec-11
Pebbledale to Willow Oak 230 kV Line	Jun-09
Wheeler Road to Davis 230 kV Line	Jun-10
Willow Oak to Wheeler Road 230 kV Line	Jun-12
Davis Road to Dale Mabry 230 kV Line	Jun-12
Lake Agnes to Gifford 230kV line	Jun-11

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 to remain at this level throughout the short term horizon. The current export capability of 1,500 MW is expected to increase to 1600 MW throughout the short term horizon.

Operational Issues

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. In addition, there are no foreseen environmental and/or regulatory restrictions that can potentially impact reliability in the FRCC region throughout the assessment period.

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, system reconfiguration, reactive device control, and transformer tap adjustments to successfully mitigate the line loading and voltage concerns that occur in real time.

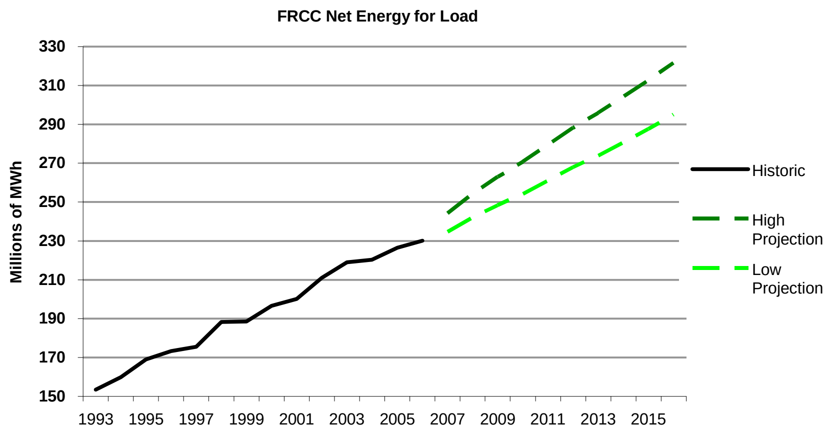
If the FRCC region experiences higher than expected load levels, the same sensitivities to area dispatches and transmission configuration are expected as operational issues through the summer of 2010 in the Central Florida area. Unplanned outages of generating units may aggravate the existing transmission constraints. However, it is also anticipated that, should any operational issues arise; pre-planning, training and operational strategies will adequately manage and mitigate the impacts to the bulk system in the area.

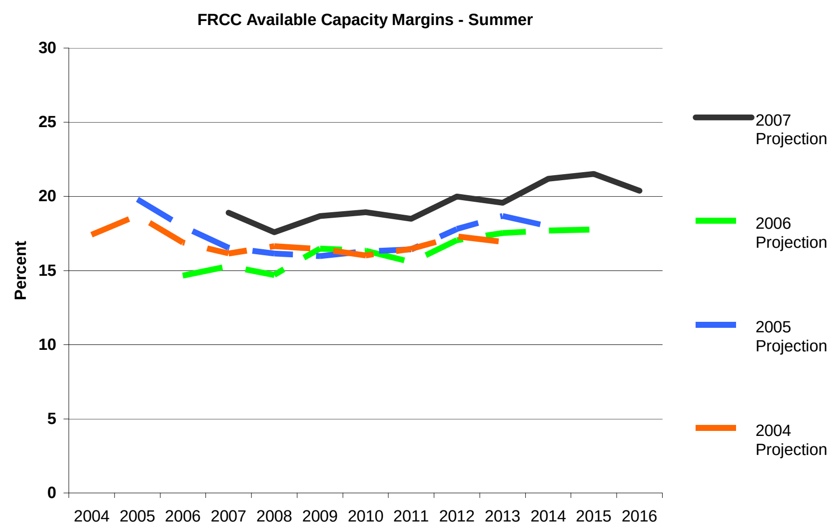
Even with increased reliance on operational procedures to resolve potential transmission loading concerns in the short term, FRCC does not foresee any reliability issues for the study period.

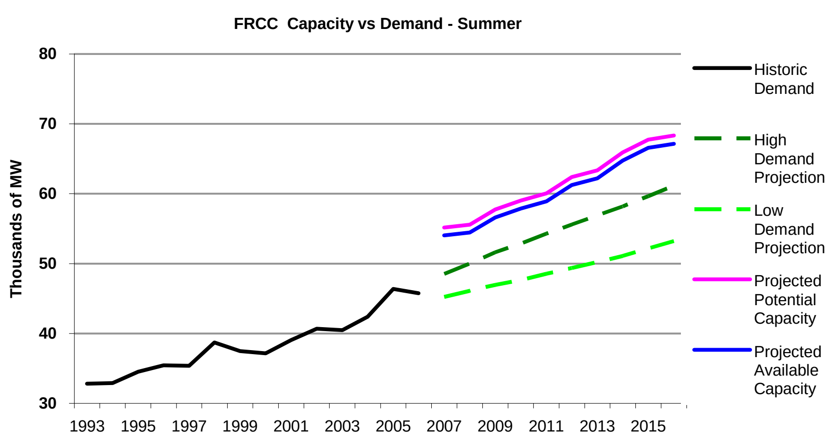
Region Description

FRCC's membership includes 27 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 control areas. As part of the transition to the ERO, FRCC has registered 109 entities (both members and non-members) 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 website (http://www.frcc.com).

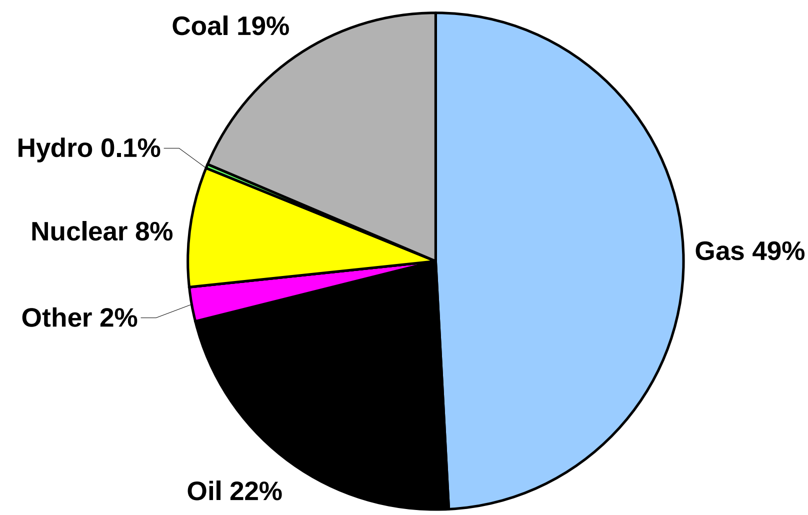
FRCC Capacity and Demand



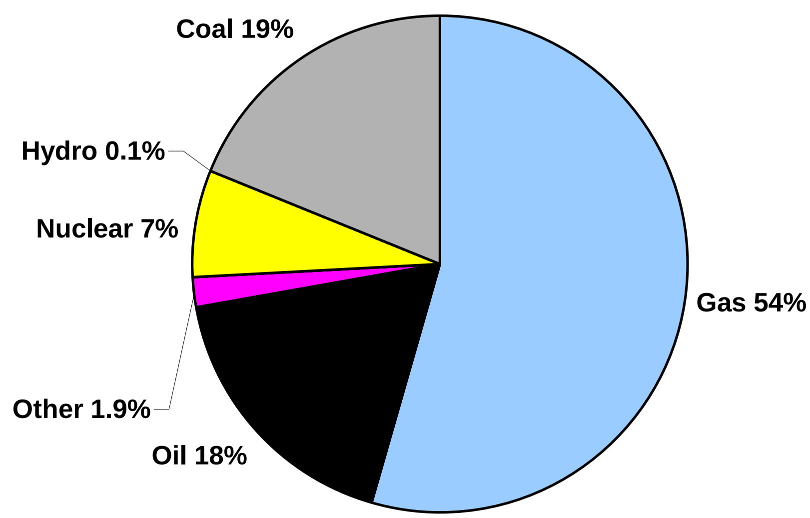




FRCC Capacity Fuel Mix 2006



FRCC Capacity Fuel Mix 2012



MRO

The MRO Reliability Assessment Committee is responsible for the long-term reliability assessment. The MRO Transmission Assessment Subcommittee, MRO Resource Assessment Subcommittee, the MAPP Transmission Planning Subcommittee, the ATCLLC and SaskPower all contribute to this MRO long-term Reliability Assessment.

Peak Demand and Energy

The MRO-U.S. summer peak demand is expected to increase at an average rate of 2.3 percent per year during the 2007–2016 period as compared to 1.9 percent predicted last year for the 2006–2015 period**.** The MRO-U.S. 2016 non-coincident summer peak demand is projected to be 50,549 MW. This projection is 6.4 percent above the 2015 non-coincident summer peak demand predicted last year (47,515 MW).

The MRO-Canada summer peak demand is expected to increase at an average rate of 1.1 percent per year during the 2007–2016 period, as compared to 0.84 percent predicted last year for the 2006–2015 period. The MRO-Canada 2016 non-coincident summer peak demand is projected to be 6,317 MW. This projection is 4.8 percent above the 2015 non-coincident summer peak demand predicted last year (6,026 MW).

While the MRO region as a whole is summer-peaking, MRO-Canada is a winter-peaking subregion . The MRO-Canada winter peak demand is expected to increase at an average rate of 1.0 percent per year during the 2007–2016 period, as compared to 0.8 percent predicted last year for the 2006–2015 period. The MRO-Canada 2016 non-coincident winter peak demand is projected to be 7,632 MW. This projection is 3.4 percent above the 2015 non-coincident winter peak demand predicted last year (7,382 MW).

The differences in the ten year projections are due to the fact that 2016 demand is being compared to 2015 demand and also due to the compounding effect of the different load growth rates over the ten year period.

MRO's peak demand forecast includes factors involving expected economic trends (industrial, commercial, agricultural, residential) and normal weather patterns. From a regional perspective, the fact that the projected growth rate in this year's demand forecast is higher than that in last year's can be attributed to improvements in economic conditions within the MRO footprint and new forecast trending after the hot 2007 summer that followed a number of mild summers.

The 2007 annual forecast energy consumption for MRO-Total (272,962 GWh) is 2.6 percent above the 2006 annual actual energy (266,006 GWh).

The MRO 2016 annual forecast energy is projected to be 325,928 GWh for the entire footprint. The MRO annual forecast energy is expected to increase at an average rate of 2.2 percent per year during the 2007–2016 period.

The 2007 annual forecast energy consumption for MRO-U.S. (229,550 GWh) is 3.1 percent above the 2006 annual actual energy (222,748 GWh). The MRO-U.S. 2016 annual forecast energy is projected to be 277,206 GWh. The MRO-U.S. annual forecast energy is expected to increase at an average rate of 2.3 percent per year during the 2007–2016 period.

The 2007 annual energy consumption for MRO-Canada (43,414 GWh) is 0.3 percent above the 2006 annual actual energy (43,258 GWh). The MRO-Canada 2016 annual forecast energy is projected to be 48,722 GWh. The MRO-Canada annual forecast energy is expected to increase at an average rate of 1.4 percent per year during the 2007–2016 period.

Demand Response Programs - Interruptible Demand and Demand Side Management (DSM) programs, presently amounting to approximately 4 percent of the MRO's Projected Net Internal Peak Demand, are used by a number of MRO members. A wide variety of programs, including direct load control programs such as electric appliance cycling and interruptible load, are used to reduce peak demand.

Load Sensitivity Analysis- MRO members continue to forecast load based on normal weather conditions.

Peak demand uncertainty and variability due to extreme weather and/or other conditions are accounted for within the determination of adequate generation reserve margin levels. Both the MAPP Generation Reserve Sharing Pool (GRSP) members and the former MAIN members within MRO use a Load Forecast Uncertainty (LFU) factor within the calculation for the Loss of Load Expectation (LOLE) and/or the percentage reserve margin necessary to obtain an LOLE of 0.1 day per year or one day in ten years. The load forecast uncertainty factor considers uncertainties attributable to weather and economic conditions. For the MAPP GRSP members, it is their individual responsibility to plan for load forecast uncertainty and extreme weather in order to meet the pool's reserve capacity obligation subject to after-the-fact audit and financial incentive.

High and low demand forecasts for the Saskatchewan region of MRO-Canada were simulated using a Monte Carlo method to reflect economic and weather uncertainties. This model considers each uncertainty independently from other variables and assumes a probability distribution around the expected demand forecast. Results are based on an 80 percent confidence interval, meaning there is an 80 percent probability of the demand falling within the bounds created by the high and low forecasts.

Resource Adequacy Assessment

MRO members are accountable for meeting the planning reserve margins that apply to them. The MRO region is comprised of non-retail access jurisdictions (except the upper peninsula of Michigan) where MRO members have an obligation to serve load. In addition, the MRO is proposing a resource adequacy assessment standard which requires an annual load and capability assessment. Typically these members assess how best to meet their required margins by considering self-built generation, merchant generation, demand-side management, and firm power purchases with firm deliverability.

The MRO region is composed of three groups, each with a distinct reserve margin target. The MAPP GRSP has a 15 percent reserve capacity obligation, which is originally based on an LOLE analysis to meet a criterion of 1 day in 10 years, and this requirement has been periodically reaffirmed by subsequent LOLE analysis. For former MAIN members now within MRO who do not belong to the MAPP GRSP, generation resource adequacy is assessed based on LOLE studies previously conducted by the MAIN region. Although conducted on a yearly basis, MAIN's LOLE studies consistently recommended a minimum long-term planning reserve margin of 16 percent. Saskatchewan's reliability criterion is based on an annual expected unserved energy analysis (EUE) and equates to an approximate 15 percent reserve margin requirement.

Adequate generating resources for the winter-peaking MRO-Canada are forecasted over the ten-year period. Reserve levels range from 29.8 percent in winter 2007/08 decreasing to a low of 26.8 percent in winter 2010/11, and rebounding to 38.9 percent in winter 2016/17. For the summer seasons, reserve levels range from 38.4 percent in summer 2007 decreasing to a low of 33.0 percent in summer 2011, and rebounding to a high of 56.4 percent in summer 2016.

Current planned capacity reported in the MRO-U.S. region is below MRO targets for adequate reserve margins during the 2010-2016 period. For the purpose of this assessment, the MRO uses a 15 percent region-wide reserve margin as a proxy measure of adequacy, which is representative of the range of reserve margin targets (10-18 percent) for the three groups within the MRO. The summer reserve margin is forecast to decline from a high of 19.3 percent in summer 2007 to 13.7 percent in 2010 and 6.2 percent in 2016. These figures include an additional 4,927 MW of new generation and 133 MW of planned generator retirements for the period of 2007-2016 as reported to NERC. However, past experience indicates that capacity additions, not included in the assessment, such as merchant plants or generation not yet sited will likely alleviate the future capacity deficits.

The MAPP Reserve Sharing Pool comprises a large part of the MRO region and a contractual enforcement mechanism within the MAPP Reserve Sharing Pool provides those pool members with a financial incentive to meet their reserve capacity requirements until May 1, 2008, after which the financial incentive will be suspended. Further assurance of the assessment of generation adequacy is expected through the development of an MRO Planned Resource Adequacy Assessment Standard. This standard is currently in the commenting period. Additionally, members can build certain types of generation within a relatively short period of time, making long lead-times unnecessary. Therefore, for the next ten-year period, the MRO capacity margins are likely to be higher than those shown above. Consequently, the MRO does not expect any capacity deficits to occur beyond 2010.

During 2007-2016, MRO's firm purchases from the neighboring regions consist of 205-230 MW from SPP and 5.5 MW from WECC. During the same period, MRO's firm sales to the neighboring regions consist of 77 MW (in 2007) to RFC and 24 MW to WECC.

There are no new nuclear plants anticipated to be built within the MRO region within the next 10 years. Wind resources will likely continue to increase as a percentage of total resources within the MRO region over the next 10 years. North Dakota has a state objective to meet 10 percent of their energy needs with renewable or recycled resources by 2015. Montana has recently passed a renewable energy law requiring utilities to meet 15 percent of their energy needs with renewable resources by 2015. Wisconsin has an initiative to meet 10 percent of their energy needs with renewable resources by 2015, and Minnesota recently passed a renewable energy bill that requires 25 percent of the state's energy needs to be provided by renewable resources by 2025. The majority of this renewable energy will come from new wind farms. The generation interconnection queues of the MAPP members and the Midwest ISO are very indicative of these initiatives with many prospective new wind farms already listed in these queues.

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

Fuel Supply and Delivery

Unless the MRO identifies a known or anticipated fuel supply or delivery issue, this topic is not addressed in the MRO's resource adequacy assessment due to the diversity in fuel supply and/or attainment methods throughout the region. However, the MRO and its members continue to closely monitor the delivery of Powder River Basin coal to ensure adequate supply. The MRO does not foresee any other significant fuel supply and/or fuel delivery issues.

Transmission Assessment

The existing and planned transmission system in the MRO area can operate at all forecasted load levels and firm transfers respecting unscheduled contingencies while meeting the relevant voltage and loading criteria without causing cascading, firm service interruptions, or instability to major portions of the MRO system.

Wisconsin - Upper Michigan System (WUMS) Area

The WUMS transmission system is expected to be reliable for the planning horizon 2007 through 2016, provided the proposed transmission projects or alternatives will be constructed and placed in service as planned and scheduled. (References 1, 2)

Major transmission projects that have been placed in service since last summer are listed below:

- Construction of a Gardner Park - Stone Lake 345 kV line.
- Construction of a Stone Lake 345 kV substation and installation of a new 345/161 kV transformer.
- Installation of a Werner West 345/138 kV substation with a 500 MVA 345/138 kV transformer.
- A number of transmission line construction, re-conductor, and conversion projects at the 138 kV level.

Major planned or proposed projects in the planning horizon 2007 through 2016 are listed below. These projects will strengthen the reliability of the WUMS system and facilitate reliable generator interconnection, market access, and transmission service.

- Construction of a Stone Lake - Arrowhead 345 kV line (2008)
- Construction of a Gardner Park - Central Wisconsin 345 kV line (2009)
- Construction of a Morgan - Central Wisconsin - Werner West 345 kV line (2009)
- Construction of a Cranberry - Conover 115 kV line, installation of a 138/115 kV transformer at Conover, & conversion of an existing 69 kV line to 138 kV from Conover to Plains (2009)
- Construction of a Rockdale - West Middleton 345 kV line (2013)
- Construction of a West Middleton - North Madison 345 kV line (2016)

Iowa Area

MidAmerican Energy Company has completed all the system upgrades to increase the QC West flowgate TTC from 1,530 MW to 1,741 MW in the summer of 2007.

Current and future plans include:

1. Upgrading of terminal equipment and line structures on the Cordova – Sub 39 345 kV line to a rating of 1,333 MVA has been completed.
2. Review and upgrading of the river crossing tension on the Quad Cities – Sub 91 345 kV line to allow a rating of 1,471 MVA has been completed.
3. The Hills - Parnell 161 kV line was rebuilt to a rating of at least 260 MVA. Additional terminal equipment upgrades have been contracted out to use the full line rating capability of 260 MVA. This project is complete except for terminal equipment upgrades.
4. The Parnell - Poweshiek 161 kV line was rebuilt to a rating of at least 230 MVA. Additional terminal equipment upgrades have been contracted out to use the full line rating capability of 230 MVA. This project is complete except for terminal equipment upgrades.
5. MidAmerican rebuilt the Reasnor – Des Moines Power Station 161 kV line to a rating of 332 MVA.
6. MidAmerican completed the construction of the new Oak Grove 345-161 kV substation in early 2007 and connected that substation into the Sub 39 – Louisa 345 kV line to offload the Sub 39 345/161 kV transformer.

All of these upgrades contributed towards increased Iowa east to west transfer capabilities.

MidAmerican constructed the 790 MW coal-fired Council Bluffs Unit 4 at the Council Bluffs Energy Center (CBEC). The unit was in-service in the spring of 2007. Several transmission-related upgrades are needed for Council Bluffs Unit 4 generation outlet and to serve area loads.

1. The 124-mile CBEC – Grimes 345 kV line was energized in June 2006. The CBEC – Grimes line is double circuit 345/161 kV construction along the existing 161 kV route from Council Bluffs to Des Moines. Several other existing line sections were also reconstructed in 2006 using bundled T2-556 ACSR conductor for the 345 kV sections and a single T2-556 ACSR conductor for the 161 kV sections:

CBEC – Avoca 161 kV, 33 miles
Avoca - Atlantic 161 kV, 17 miles
Atlantic – Earlham 161 kV, 43 miles
Earlham – Booneville 161 kV, 14 miles

2. The Grimes 345/161 kV substation and 560 MVA transformer were energized in May 2006. This project is complete.

The following longer term projects are a result of the MISO eastern Iowa study to address congestion in eastern Iowa:

1. Salem 345/161 kV transformer upgrade. This project is planned for 2008.
2. Hazleton 345/161 kV transformer Unit 1 upgrade. This project is planned for 2009.
3. Salem – Lore – Hazleton 345 kV and Lore 345/161 kV transformer. This project is proposed for 2013.

Iowa wind generation capacity continues to increase. Iowa had over 936 MW (nameplate) of installed wind generation capacity as of January 1, 2007. Several state incentives encouraging additional wind generation will continue to increase the wind penetration in Iowa. MidAmerican Energy Company plans to upgrade 104 miles of 161 kV lines in response to new wind generation.

Minnesota Area

Several bulk transmission system improvement projects in the Twin Cities area have recently been completed or are currently under way, and various additional facility additions and upgrades have been proposed for the study period. Future facility upgrades and capacitor additions in the Twin Cities area, along with selective reconductoring and new line additions, will eliminate currently identified limitations in this area.

Committed projects in the Twin Cities area for 2007 include a new 345/115 kV transformer at the Sherco substation, reconstructing the Monticello - Salida Tap - St. Cloud 115 kV line to 310 MVA summer rating, upgrading the St. Louis Park - Aldrich 115 kV line to 310 MVA summer rating, and a new Air Lake – Vermillion - Empire 115 kV line.

Major planned transmission enhancements in the Twin Cities area during the next ten-year timeframe include upgrading the Parkers Lake 345/115 kV transformers to 672 MVA (2008-2010) and upgrading Eden Prairie 345/115 kV transformers to 672 MVA (2008-2010).

CapX 2020 is a transmission planning effort by a coalition of several utilities in and around Minnesota. The mission of CapX 2020 is to create a joint vision of required transmission infrastructure investments needed to meet growing demand for electricity in Minnesota and the surrounding region to the year 2020. The CapX 2020 Group 1 transmission system improvements identified in the CapX 2020 studies include:

- Fargo - St. Cloud 345 kV line

- Brookings, S D - Southeast Twin Cities 345 kV line
- Southeast Twin Cities – Rochester - LaCrosse 345 kV line
- Bemidji - North Central 230 kV line

These four projects are intended to be energized in the 2012 timeframe.

CapX 2020 Group 1 projects will also address wind generation outlet concerns in the Buffalo Ridge area, loop flow on the 500 kV system in northern Minnesota and the Adams – Rochester 161 kV line

The CapX 2020 projects will help alleviate thermal and voltage limitations for winter season power transfers from MRO-US to MRO-Canada. These transfers are currently limited by various post-disturbance (loss of 500 kV or 345 kV transmission) loading and voltage stability concerns in the Red River Valley area of eastern North Dakota and northwestern Minnesota. The capability of the transmission system to supply peak loads in and around the Red River Valley has also become limited by these same concerns.

In addition to the improvements in the Twin Cities metro area, Xcel Energy is also pursuing development of transmission upgrades in the area of the Buffalo Ridge wind farms in southwestern Minnesota. The proposed facilities provide transmission outlet capacity for an additional 400 MW of wind generation (825 MW total). The proposed transmission system improvements include a 94-mile 345 kV circuit and numerous transformer and 69 kV, 115 kV, and 161 kV line additions and upgrades.

Nebraska Area

There are several new bulk transmission system facility improvements and expansion plans under development in the Nebraska area.

Lincoln Electric System (LES) is constructing a new 26-mile 345 kV line from the Wagener Substation to the NW68th & Holdrege substation. This line is being routed around the northern perimeter of Lincoln and is planned to be in-service by 12/31/2008.

The Omaha Public Power District (OPPD) is constructing a second coal-fired generating unit at the Nebraska City Power Station. Nebraska City Unit 2 (NC2) is expected to begin commercial operation in the spring of 2009 with a nominal net output of 663 MW. The NC2 Transmission plan includes:

- Build 50 miles of new 345 kV line from OPPD S3458 to LES 103rd & Rokeby Road (in-service 12/31/2008)
- Build a new 103rd & Rokeby Road 345 kV substation (tapped into the Wagener – Moore 345 kV line) (LES project, late 2008)
- Add a second 345/161 kV autotransformer at the OPPD S3455 substation

Nebraska Public Power District (NPPD) is replacing two exiting 187 MVA 230/115 kV transformers at North Platte with two new 336 MVA transformers planned to be completed in 2009. NPPD and Western Area Power Administration (WAPA) are pursuing a joint project to address the contingency loading issues associated with the existing two 250 MVA 345/230 kV Grand Island transformers. The recommended plan is to install a third 345/230 kV transformer at the Grand Island substation (2009).

NPPD is planning the construction of the Columbus / Norfolk / Lincoln 345 kV transmission expansion plan to address summer peak load voltage issues and enhance the reliability of the eastern Nebraska regional transmission system. This project is identified as the Electric Transmission Reliability (ETR) Project for east central Nebraska. The project is targeted for completion by 2010 and includes the following facilities:

- New 68-mile 345 kV transmission line from Columbus East to LES NW68th & Holdrege
- New 12-mile 345 kV transmission line from Columbus East to Shell Creek
- 345 kV Conversion of 45 miles of existing 230 kV line from Shell Creek to Hoskins
- New Shell Creek 345/230 kV substation

The Public Power Generation Agency (PPGA) is a non-profit entity formed in the state of Nebraska to plan and construct a new 220 MW coal-fired generating unit at the existing Whelan Energy Center site near Hastings, Nebraska. There are a number of new 115 kV substation and transmission line additions planned to accommodate the interconnection and delivery of the new Whelan Energy Center Unit # 2 (Spring of 2011).

Dakotas Area

Transmission additions associated with the Big Stone Unit 2 in South Dakota, which is planned for a 2012 in-service date, consist of the following 345 kV, 230 kV, and lower voltage additions and upgrades:

- New 230 kV Big Stone - Ortonville line
- Upgrade the Ortonville - Johnson Junction 115 kV line to 230 kV
- Upgrade the Johnson Junction - Morris 115 kV line to 230 kV
- New 230 kV Big Stone - Canby line
- Upgrade the Canby - Granite Falls 115 kV line to 230 kV

Additional third party voltage and loading issues are being examined, and mitigation may be proposed.

Additional facilities in the Dakotas area associated with new planned generation will consist of 230 and 345 kV additions from the coal fields of North Dakota to the Red River Valley in Western Minnesota, and 345 kV and 230 kV additions in South Dakota to south western Minnesota. Specific transmission facilities for these generation projects have not yet been finalized.

Queued projects for wind generation total several thousands of megawatts. Currently facilities committed or under construction number in the low hundreds of megawatts. In the last several years, several hundred megawatts of wind generation have been installed in the Dakotas. Wind generation typically has a very fast planning and construction period, and it is anticipated that wind generation will continue to be installed in the Dakotas at 100-200 MW per year.

Manitoba Area

The Manitoba Hydro system demonstrates adequate performance in terms of facility loading and voltages with various operating conditions for the 10-year period. There are no existing constraints from a system planning perspective.

The following major projects are currently planned in order to maintain adequate reliability in the Manitoba area into the future:

1. Wuskwatim Generation Outlet Facilities consist of 298 miles of 230 kV transmission to interconnect the new 223 MW hydro generating plant into the Manitoba northern ac grid, including the:

    - Thompson Birchtree - Wuskwatim line (2007)
    - Two Wuskwatim - Herblet Lake lines (2009)
    - Herblet Lake - The Pas Ralls Islands line (2010)
    - Thompson Birchtree static VAR compensator (2011)

2. Dorsey Bus Enhancement consists of the addition of four 230 kV circuit breakers and a new connecting bus. This project reduces the risk of a Category D event occurring at Dorsey.

3. New 500/230 kV Reil substation consists of establishing a new station which will include:

    - Installing a 500/230 kV transformer bank
    - Sectionalizing the existing Dorsey – Forbes 500 kV line
    - Sectionalizing two existing 230 kV lines (Ridgeway – St. Vital lines R32V and R33V)

4. Winnipeg Area Transmission Refurbishments consist of an estimated 183 miles of 230 kV and 76 miles of 115 kV transmission lines will be upgraded to carry higher loading.

5. Selkirk Area Improvements consists of a new Rosser – Parkdale 230 kV transmission line and development of a new 230/115 kV Parkdale substation. Also at Rosser, a 230/115 kV 176 MVA third transformer bank will be replaced with a 250 MVA transformer.

6. Rosser - Silver 230 kV transmission line consists of 56 miles of new transmission and reuse of a 9 miles section of the former 230 kV line (A4D).

7. Souris - Pembina Valley 230 kV Project consists of a new 230/66 kV substation and line (C28R) that will be sectionalized into that substation. This new configuration will transform line C28R into two independent 230 kV lines.

Saskatchewan Area

No significant changes have occurred in the Saskatchewan transmission system. The following major projects are currently budgeted in order to maintain adequate reliability in the Saskatchewan area:

- Addition of a 200 MVAR static VAR system in central Saskatchewan in 2009 to mitigate post-contingency voltage support issues.
- Addition of a 115 miles 230 kV transmission line and a 230/138 kV 333 MVA autotransformer in south-central Saskatchewan in 2010 to mitigate post-contingency overloads and provide voltage support.

Operational Issues

No environmental or regulatory restrictions have been identified at this time that could potentially impact reliability within the MRO region.

Regarding unusual operating conditions, snow pack in Montana is about 75 percent of normal. Main stem reservoir storage stands at about 64 percent (as of Spring 2007). The Army Corp of Engineers master plan allows for operations during drought conditions, and is planned so as to keep river flows on the river adequate to maintain cooling water for thermal plants located on the Missouri River.

The MRO does not anticipate any major generation outages, transmission outages, or temporary operating measures that may impact reliability for any extended periods.

Other Issues

Because wind is an intermittent resource, the operational impacts of the large amount of proposed wind generation in the MRO region will need to be closely monitored for any reliability impacts. (Reference 4)

Since the blackout of August 14, 2003, an undervoltage load shedding (UVLS) study and an underfrequency load shedding (UFLS) study have been completed for the MRO region (Reference 5). The UFLS study will be a key input into an MRO regional standard that will complement NERC PRC-006-0 and PRC-007-0 Standards. On March 29, 2007, the MRO Generator Testing Review Task Force completed an MRO Board-approved document entitled "MRO Generator Testing Guidelines." This document establishes MRO guidelines for complying with NERC generator performance verification standards MOD-024-1, MOD-025-1, MOD-026-1 MOD-027-1, PRC-019-1, and PRC-024-1.

In October 2006, the MRO established a Protective Relay Task Force. This task force addresses all aspects of the NERC PRC Standards and coordinates efforts with the NERC System Protection and Control Task Force (SPCTF), which was formed in response to the August 14, 2003 Blackout. A vegetation management process and personnel training have been developed, and monthly updates are required. The MRO has reviewed or is reviewing all regulatory-approved and NERC Board of Trustees (BOT)-approved standards and is creating regional procedures and standards as needed. These regional procedures and standards will help to assure that the MRO is properly addressing all NERC BOT-approved standards. Additionally, MRO staff has observed that during compliance audits that MRO members have increased training to address the mandatory standards regime.

References

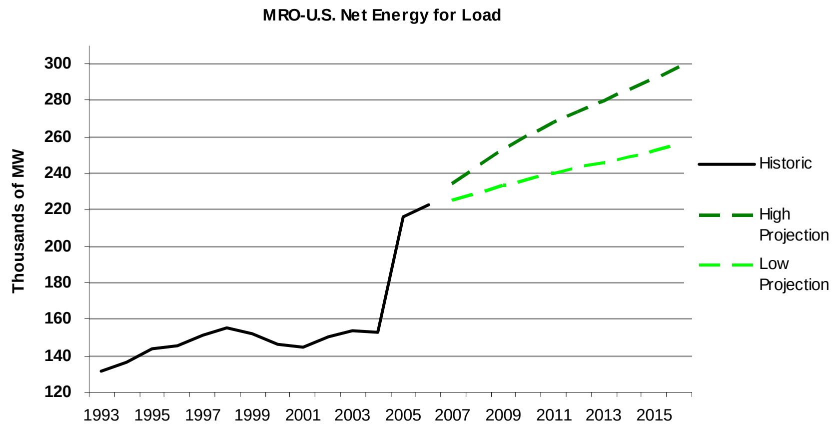
1. 2006 – ATCLLC 10-Year Transmission System Assessment. *http://www.atc10yearplan.com* (2007 ATCLLC 10-Year Transmission Assessment on-going)
2. 2006 - Reliability First Corporation (RFC) Near-Long Term Transmission Assessment Studies, *http://www.maininc.org/* (2007 - Reliability First Corporation (RFC) Near-Long Term Transmission Assessment Studies on-going)
3. MAPP Transmission Assessment 2007-2016
4. *http://www.awea.org/newsroom/releases/Groundbreaking_Minnesota_Wind_Integration_Study_121306.html*
5. *http://www.midwestreliability.org/Reliability_docs.html*

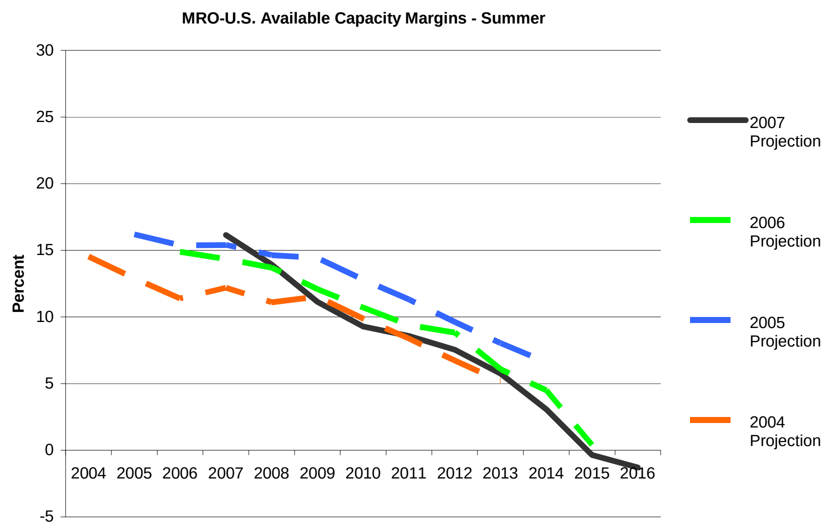
Region Description

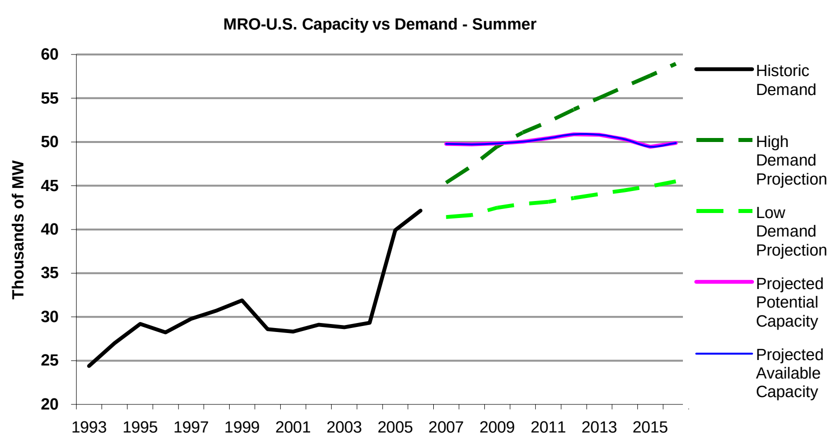
The Midwest Reliability Organization (MRO) is a voluntary association committed to safeguarding reliability of the bulk electric power system in the north central region of North America. The essential purposes of the MRO are: (1) the development and implementation of regional and NERC reliability standards, (2) determining compliance with those standards, including enforcement mechanisms, and (3) providing seasonal and long-term assessments of bulk electric system reliability. The MRO also provides other services consistent with its reliability charter.

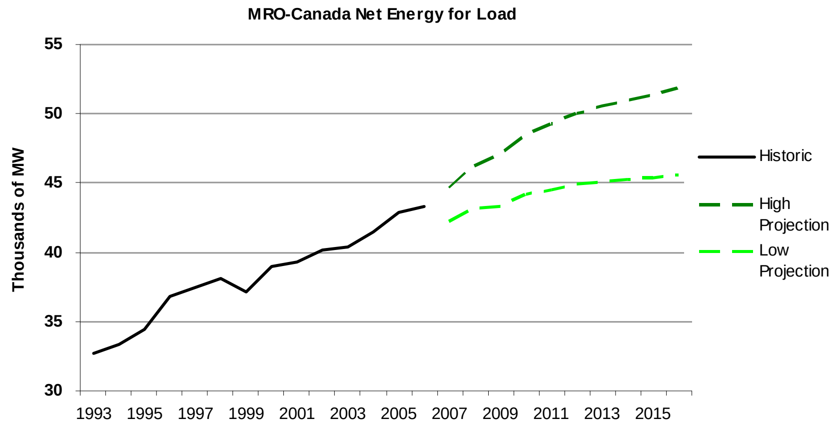
The MRO region includes more than forty organizations supplying approximately 280,000,000 megawatt-hours to more than twenty million people. The MRO membership includes municipal utilities, cooperatives, investor-owned utilities, one federal power marketing agency, Canadian Crown Corporations, and independent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

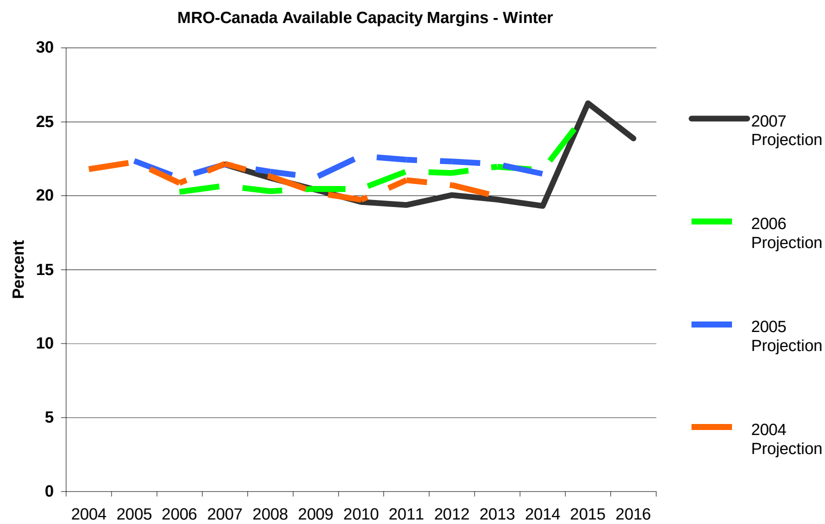
MRO Capacity and Demand

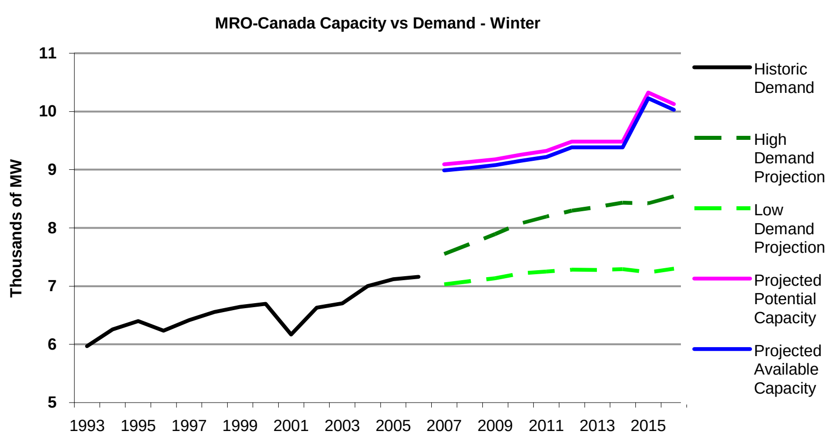


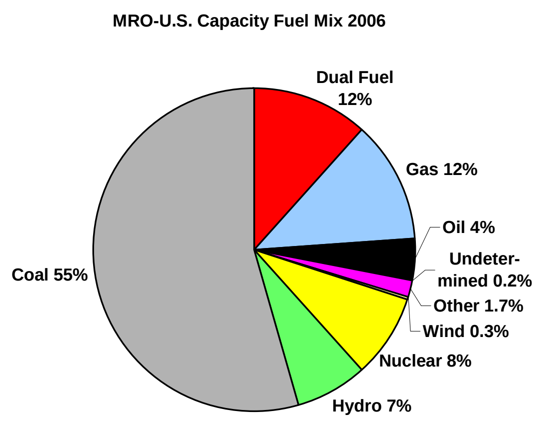


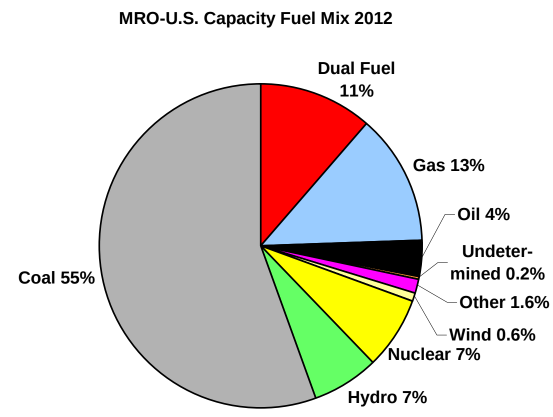


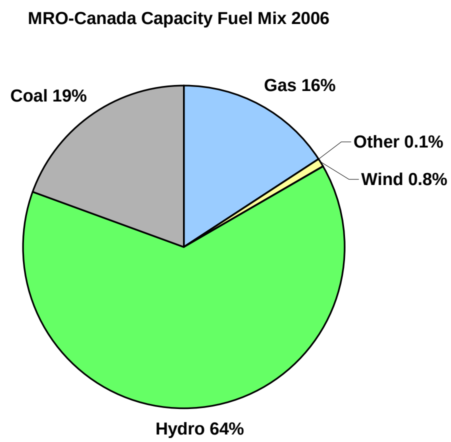

MRO-Canada Net Energy for Load
Thousands of MW
55
50
45
40
35
30
1993 1995 1997 1999 2001 2003 2005 2007 2009 2011 2013 2015
Historic
High Projection
Low Projection

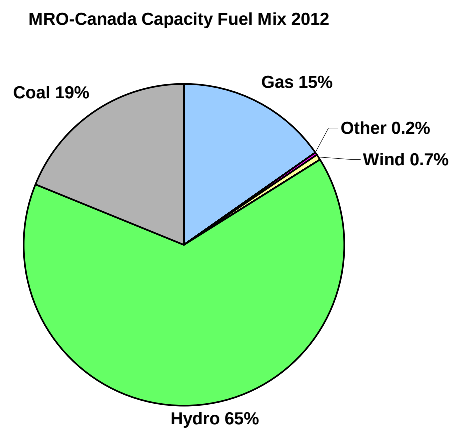

MRO-Canada Available Capacity Margins - Winter
Percent
30
25
20
15
10
5
0
2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016
2007 Projection
2006 Projection
2005 Projection
2004 Projection


MRO-Canada Capacity vs Demand - Winter
Thousands of MW
11
10
9
8
7
6
5
1993 1995 1997 1999 2001 2003 2005 2007 2009 2011 2013 2015
Historic Demand
High Demand Projection
Low Demand Projection
Projected Potential Capacity
Projected Available Capacity


MRO-U.S. Capacity Fuel Mix 2006
Dual Fuel 12%
Gas 12%
Oil 4%
Undeter-mined 0.2%
Other 1.7%
Wind 0.3%
Nuclear 8%
Hydro 7%
Coal 55%


MRO-U.S. Capacity Fuel Mix 2012
Dual Fuel 11%
Gas 13%
Oil 4%
Undeter-mined 0.2%
Other 1.6%
Wind 0.6%
Nuclear 7%
Hydro 7%
Coal 55%


MRO-Canada Capacity Fuel Mix 2006
Coal 19%
Gas 16%
Other 0.1%
Wind 0.8%
Hydro 64%


MRO-Canada Capacity Fuel Mix 2012
Coal 19%
Gas 15%
Other 0.2%
Wind 0.7%
Hydro 65%

NPCC

Coordinated NPCC Assessment Process

The NPCC Reliability Assessment Program (RAP) brings together the efforts of the Council and its members in the coordinated assessment of the reliability of the bulk power system of NPCC. 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 following five NPCC Task Forces which address the major technical disciplines of planning, operations, system protection, energy management systems and cyber security:

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 assessment of transmission reliability and resource adequacy is directed to the five NPCC Areas: the Maritimes Area (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).

Resource Adequacy Assessment

The Northeast Power Coordinating Council has in place a comprehensive resource assessment program directed through NPCC Document B-08, "Guidelines for Area Review of Resource Adequacy"[120]. This document charges the NPCC Task Force on Coordination of Planning (TFCP) to conduct periodic reviews of resource adequacy for the five NPCC Areas. 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"[121]. As quoted from Section 3.0 of Document A-02:

> **"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 these 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."**

[120] https://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/new/B-08.pdf

[121] http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/A-02.pdf

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 at least every three years, 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;
- Ability of the Area to reliably meet projected electricity demand, assuming a high growth load forecast for the Area and the proposed resource scenario;
- Impact of load and resource uncertainties on projected Area reliability, discussing any available mechanisms to mitigate potential reliability impacts;
- Proposed resource capacity mix and the potential for reliability impacts due to the transportation infrastructure to supply the fuel;
- Internal transmission limitations; and
- Impact of any possible environmental restrictions.

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 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 the NPCC Area 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 an 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.

Transmission Assessment

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"[122]. 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.

[122] http://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/b-04.pdf

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.

As part of its coordinated assessment and replication of the events of August 14, 2003, the Task Force on System Studies has also carried out an extensive analysis of the NPCC underfrequency load shedding program, including:

- Sensitivity studies to examine the impact of unexpected load or generation loss near the electrical center of unstable swings during island formation;
- Continued pursuit of coordination between generating unit (generator, excitation system and prime mover) protection systems and the underfrequency load shedding program;
- Simulation of island formation across Area and Regional boundaries, including the modeling of more extreme events;
- Assessment of the impact of extremely low voltages on the performance of the underfrequency load shedding program; and
- Identification of large load areas within NPCC that is deficient in generation by more than 25 percent that are susceptible to islanding and may accordingly require additional under frequency load shedding.

Based on the results of the above investigations, potential enhancements to the NPCC UFLS program may be identified and recommended.

Maritimes

The footprint of the Maritimes Area covers 60,000 square miles and is comprised of the provinces of New Brunswick (served by the New Brunswick System Operator), Nova Scotia (served by Nova Scotia Power Inc.), Prince Edward Island (served by the Maritime Electric Company Ltd.) and the Northern Maine Independent System Administrator, Inc (NMISA), serving approximately 40,000 customers in northern Maine and radially connected to the New Brunswick power system. The Maritimes Area is a winter peaking region serving almost one million customers.

On October 1, 2004, New Brunswick's Electricity Act restructured the electric utility industry in New Brunswick and created the New Brunswick System Operator (NBSO). It is an independent not-for-profit statutory corporation separate from the NB Power group of companies. The Electricity Act transferred the responsibility for the security and reliability of the integrated New Brunswick electricity system from NB Power to NBSO, and also made NBSO responsible for facilitating the development and operation of the New Brunswick Electricity Market. These responsibilities take the form of operation of the NBSO controlled grid and administration of the NBSO Open Access Transmission Tariff (OATT) and the New Brunswick Market Rules. On February 1, 2007, the Nova Scotia Electricity Act came into effect, enabling wholesale market access with the implementation of the Nova Scotia Market Rules. The Nova Scotia Power System Operator (NSPSO) is that function of Nova Scotia Power, Incorporated (NSPI) responsible for the reliable operation of the integrated power system in Nova Scotia, as well as administration of the NS Market Rules and the Nova Scotia OATT which has been in effect since November 1, 2005.

By contractual agreement, the NBSO acts as the Reliability Coordinator for the Maritimes Area.

Peak Demand and Energy

Separate demand and energy forecasts are prepared by each of the Maritimes Area jurisdictions, as there is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes Area. For Area studies, the individual forecasts are combined using the load shape of each jurisdiction.

The 2007/08 peak demand forecast, representing the summation of the forecasts of each Maritimes Area jurisdiction, is 5,974 MW. This is 138 MW higher than last year. The forecast average annual peak demand growth rate is 1.7 percent over the next 10 years, and this is slightly higher than the 1.6 percent growth rate forecast last year. One of the key factors driving the year-to-year changes in the Maritimes peak forecast is the assumptions for large industrial customers. Due to the relatively small size of the Maritimes Area, a change in the plans of a single large industrial customer can result in a significant change to the load forecast.

The 2007/08 energy demand forecast for the Maritimes Area is 30,505 GWh, which is 530 GWh lower than last year. The average annual energy demand growth rate is 1.6 percent, and this is higher than the 1.3 percent forecast last year. Some key factors driving the year-to-year changes in the Maritimes energy demand forecast include the assumptions for natural gas switchover by homeowners to offset home heating load, and energy efficiency assumptions resulting from new government legislation and programs.

The NBSO load forecast for New Brunswick is based on 30-year average temperatures (1971-2000) with the annual peak hour demand determined for a design temperature of -24°C over a sustained 8-hour period. It is prepared based on a cause and effect analysis of past loads, combined with data gathered through customer surveys, and an assessment of economic, demographic, technological and other factors that affect the utilization of electrical energy.

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

The Maritime Electric Company, Limited (MECL) load forecast for Prince Edward Islands (PEI) uses an econometric model that factors in the historical relationship between electricity usage and economic factors such as gross domestic product, electricity prices, and personal disposable income.

The NMISA load forecast for northern Maine is based on historic average peak hour demand patterns inflated at a nominal rate and normalized to 30-year average historical weather patterns. Economic and other factors may also affect the forecast.

The general load forecast methods and assumptions involving weather and economic conditions remain unchanged from previous forecasts. One large customer tariff with demand response has changed. The economic interruption component of that rate has effectively been replaced with a real-time pricing component. It is forecast to reduce peak demand by an additional 23 MW.

The Maritimes Area has about 600 MW of interruptible demand from large industrial customers. About 400 MW of this total is in Nova Scotia, with 140 MW in NB, and the remaining 60 MW in PEI and Northern Maine.

Nova Scotia currently has two customer tariffs which invoke price-based demand response. The residential time-of-day rate involving over 4000 customers with electric thermal storage home heating equipment continues to grow and provides over 16 MW of peak reduction. The Extra Large Industrial Interruptible rate has been changed for 2007 from economic interruptibility to effectively a real-time pricing structure that is forecast to reduce peak demand by an additional 23 MW.

In the "2005 Maritimes Area Interim Review of Resource Adequacy[123]," compliance with the NPCC Resource Adequacy Criterion was evaluated using a Load Forecast Uncertainty (LFU) 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.

Resource Adequacy Assessment

In the "2004 Maritimes Area Triennial Review of Resource Adequacy[124]," it was shown that that the 20 percent reserve criterion of the Maritimes Area meets the NPCC Resource Adequacy Criterion that the loss of load expectation shall be no more than 0.1 days per year. The 20 percent regional reserve requirement in the Maritimes Area also accommodates load forecast uncertainty (i.e. higher peak demands) and instances of resource unavailability.

[123] https://www.npcc.org/publicFiles/documents/adequacy/Maritimes%20Interim%202005.pdf
[124] https://www.npcc.org/publicFiles/documents/adequacy/Maritimes_Area_Triennial_Review_2004.pdf

The following table compares the 20 percent regional reserve margin to the forecast surplus reserve margins for the 2007 and 2006 load forecasts:

Year	Required Reserve (MW)	2007 Forecast Surplus Reserve (+ Surplus/ - Deficit) (MW)	2006 Forecast Surplus Reserve (+ Surplus/ - Deficit) (MW)
2007/08	1079	144	322
2008/09	1098	-451	-229
2009/10	1108	231	191
2010/11	1130	120	225
2011/12	1152	263	116
2012/13	1175	219	0
2013/14	1196	90	-122
2014/15	1219	-45	-278
2015/16	1241	223	-407
2016/17	1264	86	---

The projected capacity margins indicate that the Maritimes Area will be deficient by 451 MW in 2008/09. This deficiency is due to NB Power's planned 18-month refurbishment of the 635 MW Point Lepreau nuclear generation station, scheduled from April of 2008 to October of 2009. Plans for replacement capacity through purchases to accommodate this refurbishment are still being evaluated by NB Power. This projected deficit is 222 MW higher than projected last year due mainly to a higher peak demand forecast as well as the retirement of the 98 MW Courtenay Bay 4 unit in New Brunswick.

Capacity margins are sufficient after 2008/09 until 2014/15. In 2015/16, the capacity margin returns to a surplus due to the planned addition of 400 MW of conventional generation in Nova Scotia.

The Maritimes Area 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.

200 MW of firm capacity is sold to Québec until 2010/11. There is a corresponding transmission reservation for this 200 MW on the New Brunswick to Québec interface.

Demand response by large industrial customers, including price based demand response, is accounted for as interruptible demand. The actions of residential customers with time-of-day metering is not included in the reported Demand Response, but rather included in the internal demand.

Wind projects in the Maritimes Area are credited with a MW capacity according to their demonstrated seasonal capacity factors. This credit is based upon results from the Sept. 21, 2005, NBSO report, "Maritimes Wind Integration Study,[125]" where it was shown that the

[125] http://www.nbso.ca/Public/en/docs-EN/Notices/2005%20Maritime%20Wind%20Integration%20Study%20_Final_.pdf

effective capacity from wind projects in the Maritimes Area, and their contribution to Loss of Load Expectation was equal to or better than their projected seasonal capacity factors.

The only uncommitted capacity considered are wind projects that are planned for meeting government legislated renewable energy portfolios, and 400 MW of conventional fossil-fired generation in Nova Scotia that is planned for the 2015/16 operating period. The fuel source of this fossil-fired generation project has not been determined.

The Maritimes does not have individual resources that are transmission limited. Intra-area transfer limits are considered in its NPCC Comprehensive and Interim Reviews of Resource Adequacy.

Nuclear - The planned 18-month refurbishment of the 635 MW Point Lepreau Nuclear Station is scheduled to begin in April of 2008. Upon its return to service in October of 2009, this station will have its net output increased to 658 MW. No transmission reinforcements are required for this refurbishment project.

Wind farms - Nameplate wind capacity in the Maritimes is forecast to rise from 132 MW in 2007/08 to 691 MW by 2013/14. For generation capacity calculations, the winter capacity of these farms is derated to 40 percent, while the summer capacity is derated to 20 percent. These credits are based upon conservative estimates of the expected seasonal capacity factors for the wind farms.

Conventional generation - Nova Scotia has plans for a 400 MW conventional fossil-fired generation project in 2015/16. The fuel source of this fossil-fired generation project has not been determined. This is the only new conventional generation project currently in the baseline plan for the Maritimes Area.

The only deliverability concern identified in the Maritimes Area is the intra-area transfer limit between New Brunswick and Nova Scotia. This transfer limit allows Nova Scotia to export 350 MW to New Brunswick, and import 350 MW. These limits are set below the thermal interconnection limits, and they are set at levels so as to maintain the reliability of the Nova Scotia system in the event the interconnection trips. The Maritimes Area accounts for this limitation in its NPCC Comprehensive and Interim Reviews of Resource Adequacy[1].

The Maritimes Area does not have any environmental or regulatory restrictions that could potentially impact the reliability of the electrical system.

Fuel Supply and Delivery

Due to the Maritimes Area fuel supply mix, its relatively low reliance on natural gas, and its fuel storage facilities, the potential impact of fuel supply and/or delivery interruptions in the Maritimes Area is very low, and thus it is not explicitly modeled in resource adequacy assessments.

No fuel supply or delivery infrastructure issues are anticipated that would require additional fuel supply infrastructure or mitigation procedures.

During winter peak load conditions, extreme cold temperatures should not impact the fuel supply to conventional generation stations.

Due to its fuel storage facilities, fuel switching capability of some generators, and relatively low reliance on natural gas, no fuel supply problems are anticipated that would impact the capability of the Maritimes Area to supply load during winter peak conditions.

Transmission Assessment

The second 345 kV interconnection between New Brunswick and New England is scheduled to be in-service by December of 2007. This new line, the only new transmission line at 230 kV or above in the baseline plan for the Maritimes Area, will connect Point Lepreau, New Brunswick, to Orrington, Maine. As a result of this project the maximum transfer capability from New Brunswick to New England is increased from 700 MW to 1000 MW, and the firm transfer capability from New England to New Brunswick is increased from 100 MW to 400 MW. This second intertie 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 interconnected New England power system.

Power flow patterns are anticipated to be similar to previous forecasts, and no new transmission constraints or deliverability problems are expected.

There are no specific issues related to the start-up of the Point Lepreau nuclear facility that impact the reliable operation of the transmission system. All generation projects, including wind farm, are required to undergo a System Impact Study (SIS) prior to connection to the grid[126]. The SIS will assess whether the project meets the grid connection standards in areas such as voltage support, low voltage ride through capability, and frequency response. Mitigation measures specific to wind farms include the requirement for soft start-up, whereby a limit is set on the number of turbines that may synchronize to the grid at once.

The 2005 NPCC report "Review of Interconnection Assistance Reliability Benefits – 2nd Tie Addendum"[127] confirmed that the Maritimes Area has a Maximum Tie Benefit Potential equal to its 1500 MW import capability.

Northern Maine, currently connected radially to New Brunswick only, is studying different options to possibly interconnect to the New England grid at 345 kV. These options include scenarios interconnecting both Northern Maine and 500 MW of new wind generation in Northern Maine. Due to the uncertainty of these scenarios, they are not presently included in the baseline plan.

The transmission lines planned for announced wind projects in the Maritimes Area are all at 138 kV or lower, and will not have a significant impact on the bulk system of the Maritimes Area.

No changes unique to the transmission planning of the Maritimes system have been identified as a consequence of the blackout of August 14, 2003.

[126] http://www.nbso.ca/Public/en/op/transmission/connecting/SIS.aspx

[127] https://www.npcc.org/publicFiles/documents/interconnectionAssistanceReliabilityBenefits/archives/2nd%20NB%20Tie%20Addendum(rcc).pdf

Operational Issues

There are no environmental or regulatory restrictions that could potentially impact reliability.

While extreme cold weather could force some wind turbines to shut down, this impact will be mitigated by:

- Installing turbines capable of operating at temperatures down to minus 30˚ C (-22˚ F);
- Developing a geographically diversified portfolio of wind so it is less likely that all of the wind turbines experience the extreme cold temperatures at the same time; and
- Maintaining a reasonably low reliance on wind generation for system capacity.

New Brunswick Power's refurbishment of the 635 MW Point Lepreau nuclear generation station from April 2008 to October 2009 creates a 451 MW capacity deficiency in 2008/09 for the Maritimes. Plans for replacement capacity through purchases to accommodate this refurbishment are still being evaluated by NB Power.

Wind farms are not expected to impact reliability at the present time, provided that their generation levels are forecast with a reasonable degree of accuracy, and sufficient balancing capability exists from regulating units. The development of a geographically diversified portfolio of wind generation is expected to mitigate extreme changes in wind power output production, and thus reduce the balancing problems associated with the wind farms. Wind power integration studies are currently underway in both New Brunswick and Nova Scotia.

No changes in transmission or generation operations have occurred as a result of the August 14, 2003, blackout.

New England

Peak Demand and Energy

This year's summer peak forecast ten-year compound annual average growth rate has decreased to 1.7 percent from 1.9 percent, resulting in generally lower summer peak forecasts when compared with the 2006 long-term forecast.

The projected ten-year compound annual growth rate for net annual energy also decreased slightly, from 1.3 to 1.2 percent. This change in the growth rate resulted in an energy forecast that is somewhat lower than the previous year's forecast.

Year	90/10 Load Forecast in MW
2007	29,160
2008	29,750
2009	30,430
2010	31,035
2011	31,695
2012	32,290
2013	32,830
2014	33,315
2015	33,765
2016	34,170

The key factors leading to the changes in the forecast are updated historical data, new economic and demographic forecasts, the incorporation of the transition costs into the price of electricity (defined as fixed monthly installed capacity payments made to ICAP resources) from the Settlement Agreement to install a Forward Capacity Market (FCM) in New England, and the inclusion of estimates of the capacity costs from the FCM into the price of electricity. Details on the load and energy forecasting method used by the ISO-NE with data is available on-line (http://www.iso-ne.com/trans/celt/fsct_detail/index.html)

The exposure under the extreme forecast (a 10 percent chance of being exceeded) over the ten-year study period is detailed below. Further information on the load forecast may be found in the *2007–2016 Forecast Report of Capacity Energy Loads and Transmission—April, 2007*, available at http://www.iso-ne.com/trans/celt.

Demand response resources are activated through ISO New England's Demand Response Programs. Participants within the Real-Time Demand Response Program are involved in one of two sub-programs based on their response time (30 minutes or 2 hours). Each sub-program requires the participant to interrupt during pre-specified actions of ISO New England Operating Procedure No. 4 – Actions during a Capacity Deficiency (OP 4). In addition, participants in the Real-Time Profiled Response Program are also required to respond during certain actions of OP 4. These demand response resources, which amount to over 800 MW, are considered to be "supply" resources and are not reflected in the load forecast.

In addition to the reliability-based programs, ISO-NE administers two economic programs: the Real-Time Price Response program and the Day-Ahead Demand Response Program. Both of those programs are voluntary in nature and can therefore not be counted on to reduce load.

Many assets in ISO-NE's Real-Time Demand Response programs are subject to a Market Participant's direct control. For example, there are approximately 20,000 direct load control devices installed on central air conditioning systems of residential, small commercial customers in Southwest Connecticut. In addition, many emergency generators at commercial and industrial facilities can be remotely "dispatched" by a Market Participant when ISO New England activates the Real-Time Demand Response Programs during OP4 conditions.

ISO New England addresses peak demand uncertainty in two ways:

- Weather – peak load distribution forecasts are made based on 37 years of historical weather which includes the reference forecast (50 percent chance of being exceeded), and extreme forecast (10 percent chance of being exceeded);
- Economics – alternative forecasts are made using high and low economic scenarios.

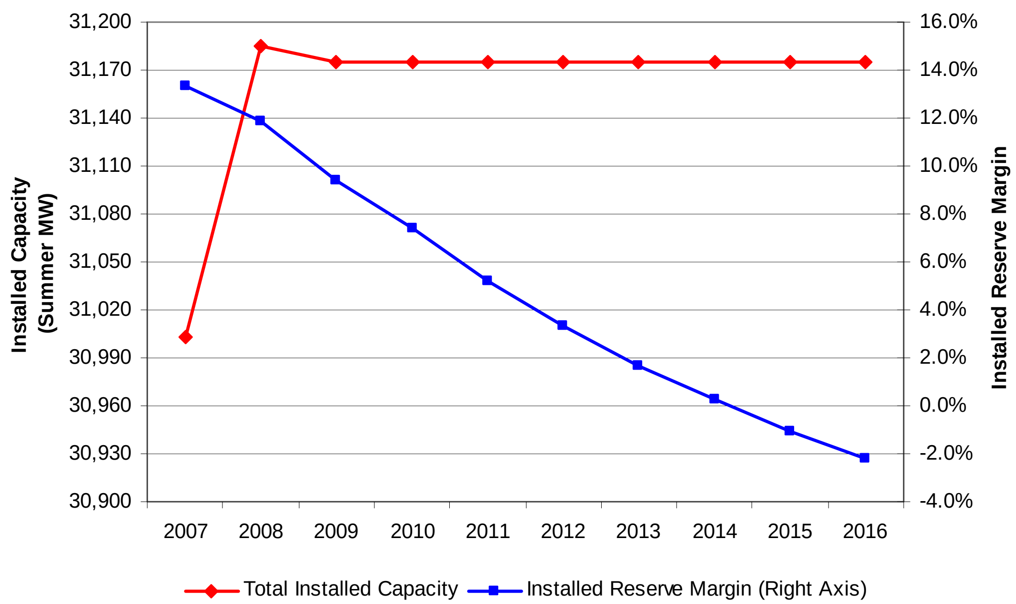
ISO New England is concerned with meeting the extreme peak demand (10 percent chance of being exceeded) based on the reference economic forecast.

Resource Adequacy Assessment

Installed reserve margins will be declining throughout the study period from a high of 13 percent in 2007 to -2 percent in 2015 if additional resources are not installed. New England does not have a particular reserve target, rather it plans resources to meet the one day in ten years loss of load expectation resource planning reliability criterion. The resulting reserve, as a percentage of the reference load forecast, can range from the low- to mid-teens. The installed reserve margins reflect net capacity purchases of 50 to 60 MW per year through 2016. In addition, new generation totaling approximately 85 MW is assumed to be installed. Neither generating unit retirements nor projected impacts of demand response programs are reflected in the above margins. The installed reserve margin calculated for the 2007 NERC Summer Assessment is 16 percent. The higher margin resulting from that analysis is due to an assumed reduction in the peak load by available interruptible demand.

The Figure below illustrates the total installed capacity as well as the installed reserve margins forecasted for the study period.

Total Installed Capacity and Installed Reserve Margins — Summer



The new generation capabilities include projects that have received proposed plan approval and are likely to be commercialized by the end of 2007. Not included in this forecast is the recently approved reactivation of 106 MW of capacity in Southwest Connecticut targeted to be in service this year. In addition, applications for over 17,000 MW of new supply-side and demand response resources have been accepted into the qualification process for possible participation in the 2010 Forward Capacity Market auction. Under the FCM, it is expected that ISO-NE will purchase the amount of installed capacity required to meet the region's resource adequacy needs. The ISO-NE expects that the total installed capacity, and therefore the resulting installed reserve margin, to improve over time.

When analyzing the resource adequacy situation of New England, only firm long-term capacity purchases and sales are included in the assessment. For the 2007 assessment, approximately 400 MW of firm purchases are forecasted through 2016. Also included in the calculation of installed reserve margins is a long-term sale of 343 MW to New York via the Cross Sound Cable.

Last year, projected installed reserve margins were 14.3 percent in 2006, rising to 14.9 percent in 2008 and then declining for the remainder of the study period to almost 0 percent in 2014. The primary factor associated with the decline from last year's forecasted reserve margins is lower installed capacity values due to more conservative projections of future generation and lower forecasted firm capacity purchases.

In the case of the 90/10 demand forecast, the reserve margins would start out at a high of 6 percent in 2007 and decline through the study period, becoming negative in 2011 and reaching a low of -9 percent in 2016.

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. Tie benefits are the amount of emergency capacity that the ISO assumes can be purchased from neighboring control areas during capacity shortage conditions. Based on multi-area tie reliability benefits studies, this amount was determined to be 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 2008 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 the winter of 2015/2016. This amount will be purchased by ISO-NE in the Forward Capacity Auction.

Fuel Supply and Delivery

The ISO-NE's resource adequacy calculations do not include potential fuel supply and/or delivery interruptions. However, the ISO-NE routinely assesses the potential for fuel-supply interruptions and their resultant impacts on system reliability in the annual Regional System Plan and when additional reliability analyses are deemed necessary. Of the three major types of fossil fuels used to produce electricity in the region, coal, oil and natural gas, both coal and oil are primarily imported via ocean-going transport and are procured through a combination of spot-market, medium- and long-term contracts. Aside from weather-related delays, coal and oil can be readily stored and stockpiled, unlike natural gas which can be considered a "just-in-time" fuel source. In the aftermath of the 2005 Hurricanes Katrina and Rita, the ISO-NE developed an "energy emergency" operating procedure that can be implemented during any time of the year, to help mitigate the operational impacts of both short and long-term fuel supply shortages. Short of domestic or international force majeure situations, the ISO-NE's forecast projects no fuel supply or delivery constraints to the generation sector during the summer peak load seasons.

During the winter, New England's natural gas-fired generators continue to compete with the core natural gas market (i.e., for space heating) for gas supply and finite transportation infrastructure. During winter peak load periods, regional natural gas pipeline capacity is not sufficient to serve the coincident demands from both the gas and electricity sectors. During extreme cold winter weather, when the demand for natural gas and electricity peak coincidently, ISO-NE has developed a "cold weather" operating procedure that can be implemented to help mitigate the loss of operable generating capacity due to gas supply and transportation nomination constraints. In preparation for winter operations, ISO-NE routinely assesses the dual fuel capability of the generation fleet as well as performs an assessment of regional gas-fired generation transportation contracts to identify the prioritization of their entitlements. Currently, only 3,200 MW of the 8,600 MW of single-fuel, gas-only capacity in New England has firm natural gas transportation contracts, which originate back to natural gas trading hubs located beyond traditional constraint points.

As noted earlier, New England's regional natural gas infrastructure was not designed or built to serve the coincident winter demands of both the core gas and electricity sectors. The regional interstate and intrastate pipelines were originally funded and built via long-term, firm contracting with regional gas Local Distribution Companies (LDCs), which correspondingly hold the majority of that firm pipeline capacity. During non-winter months, these gas LDCs release their unused pipeline capacity into the gas market, which is subsequently procured to satisfy the fuel needs of regional gas-fired generation.

In anticipation of serving the burgeoning growth within the gas-fired generation sector, numerous gas sector proposals have been made to expand the international, interstate, and intrastate pipelines serving New England as well as build new liquefied natural gas (LNG) import terminals and regasification facilities. There are currently 15 LNG projects proposed for the greater northeast U.S. and eastern Canadian region.[128] One project is scheduled for in-service by December 2007, while most others are scheduled to commercialize within the 2008 – 2010 timeframe. Not all proposed LNG projects are expected to materialize. New LNG import terminals would be beneficial in diversifying the region's gas supply portfolio. Failure to commercialize these LNG import facilities will leave the region at risk for seasonal gas supply shortages. However, these regional LNG supply options also exacerbate New England's dependence on foreign-sourced, fuel supplies.

Due to the aforementioned ISO-NE concerns over natural gas dependency, the ISO-NE encourages the expansion of single-fuel, gas-only units to dual-fuel capability in addition to promoting the procurement of firm gas supply and transportation contracts. During the past two years, over 2,300 MW of single-fuel, gas-fired capacity has been converted to dual-fuel capability. New market incentives, such as those provided by the Forward Capacity Market (FCM), are designed to promote the availability of supply and demand-side resources when needed most, which should translate into improved procurement and contracting for fuel supply.

The ISO-NE continues to work with regional air regulators to review existing power plant operating permits, with respect to clarifying language and incorporating exemption clauses that will allow limited or provisional oil-burning operation 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, coal or oil supplies have been curtailed due to *force majeure* events.

Transmission Assessment

The 2006 Regional System Plan[129] 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 253 transmission projects[130] in various stages of planning, construction, and implementation. ISO-NE and the transmission owners collaboratively conducted the

[128] Northeast Gas Association - map of existing and proposed LNG terminals: http://www.northeastgas.org/pdf/lng_terminals_0607.pdf

[129] Summaries of transmission studies and projects can be found in the ISO New England 2006 Regional System Plan, at the following link: http://www.iso-ne.com/trans/rsp/2006/rsp06_final_public.pdf

[130] The project listing can be found on the ISO New England web site at http://www.iso-ne.com/trans/rsp/index.html

studies[131] 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.

Over 50 of these 253 projects are part of six major projects that 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 New England East-West Solution, and the NSTAR 345-kV Transmission Project.

Maine-New Hampshire

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. The Y-138 Project, scheduled for 2008, closes a normally open tie between western Maine and New Hampshire. Recently, an additional circuit breaker has been added at Deerfield, to eliminate a possible stuck breaker contingency. Additional projects which are in progress are the addition of circuit breakers at 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 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 and the majority of the load is in the northwest, 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. 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. While some smaller portions of this project remain under construction, the new 345-kV line was placed in service in January of 2007.

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 continue to reliably serve load. The most significant

[131] Full transmission studies are posted on the ISO New England web site at http://www.iso-ne.com/trans/sys_studies/rsp_stud/index.html. *[NOTE: The study site is protected. Clicking on the link brings up a pop-up box that says the site can be accessed by contacting ISO-NE Customer Services.]*

contingencies in the state are the outage of the Millstone unit 3 generation (~1,200 MW) or the loss of 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 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. This problem will increase in severity with load growth.

The southwest Connecticut system was 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 that prevented the movement of power into southwest Connecticut, transmission limitations also prevented the movement of large amounts of power within the area.

A working group has developed a number of projects to address these issues. As currently being evaluated, these projects include a new 345-kV line across the East-West interface into eastern Connecticut and the creation of a new 345-kV tie from the western portion of Connecticut to Western Massachusetts. When combined, these projects should provide significant increases in both Connecticut import and East-West transfer capability.

Southwest Connecticut

In the past, the ability to transfer power into southwest Connecticut was voltage limited. The installation of both static capacitors and dynamic VAR devices helped alleviate these limiting conditions. In addition to these projects that increased reactive support in and around southwest Connecticut, two large 345-kV installations to build a 345-kV loop through the area were planned to meet the growing load demand in the area. The first portion of this installation was placed in service in October 2006, and 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. This 115-kV project is scheduled to be in service in 2008.

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 five critical 345-kV lines feeding the area, or the outage of significant generation at Salem Harbor or Mystic, for example, 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 have recently been placed in service and others are under way to relieve some of the constraints that limit Boston imports. The Ward Hill project provides significantly more transformation to 115 kV at this location and upgrades lines that travel toward Boston. This project has been placed in service. 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, was placed in service in April. The first stage of this project increases Boston-import capability by approximately 1,000 MW. The second stage of this project is currently scheduled to be in service in 2008.

Lower Southeastern Massachusetts (SEMA)

Concerns have developed regarding transmission constraints in lower southeastern Massachusetts. Recent operating experience has identified the need to develop procedures for committing units in this load pocket. The procedures assure that adequate generation has been committed to address second-contingency protection for the loss of two major 345 kV lines. This situation resulted in significant reliability costs in 2006. Studies are in progress to address this problem.

Transmission Retirement

The Monroe converter station was retired in spring 2007, resulting in decommissioning of the United States portion of the Phase I HVDC terminal facilities. Four 20 MVAR banks of switched shunt reactors, four 31.5 MVAR banks of switched capacitors, and equipment necessary for continued operation the Phase II HVDC facilities will remain in service.

Transmission Transfer Capability Studies

ISO-NE conducts Inter-Area transmission transfer capability studies for the near-term TTC on a daily basis or as topology changes warrant, and for the long-term TTC on an annual basis. Part of the process in any of ISO-NE's studies involving transmission changes or generator interconnections is to ensure that existing transfer capabilities are maintained.

Transmission Associated with Wind and Nuclear Generation

Presently, New England does not have any interconnection requests for new nuclear generation. New England has a small number of interconnection requests for wind projects, with one large proposal near Cape Cod. None of these projects require substantial transmission infrastructure to support their interconnection.

Changes in Transmission Planning Since the August 14, 2003 Blackout

New England has reviewed its transmission planning process in light of the events on August 14, 2003. While no changes in the process were necessary, New England has become more cognizant of the conditions which could cause the misoperation of special protection systems and has become more diligent in its review of these special protection systems. Pertinent discussions have been incorporated into its monthly study coordination meetings, and the NEPOOL Task Force reviews have paid special attention to these issues.

Operational Issues

No major generating unit outages that may impact reliability are anticipated for any extended periods over the next ten years. Transmission constraints during that time are, however, a concern. As described in the *ISO New England Regional System Plan 2006* (RSP06), transmission capacity constraints into Connecticut limits the amount of generation that can be delivered to that load pocket. Transmission solutions that will improve the ability to transfer power between Rhode Island, Massachusetts and Connecticut have been developed and are currently being finalized. These solutions will eliminate constraints into the Connecticut load pocket and are estimated to be placed in service in the 2010 to 2013 timeframe.

As a result of the August 14, 2003 blackout, the ISO-NE is working to understand and minimize the possibility of a similar event taking place in New England. The ISO-NE is evaluating the data-communication infrastructure and substation controllability of the existing power system. The results of this evaluation will be used to develop recommendations for improving the reliability of data acquisition and ensure that system operators are able to respond and disconnect customer load, if necessary.

New York

Peak Demand and Energy

The New York area is a summer-peaking system, and summer peak demands are expected to grow at an average rate of 1.2 percent, through 2016. This compares with 0.9 percent growth projected in the 2006-2015 assessment conducted by the RAS in 2006. 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 84.3 will result in about 600 MW of additional load.

Energy consumption is forecast to grow at an average annual rate of 1.3 percent through 2016. This compares with 0.8 percent growth projected in the 2006-2015 assessment conducted by the RAS in 2006. The increase in Demand and Energy projections are the result of stronger long term economic growth projections and data updates.

Resources Adequacy Assessment

The NYISO conducts an annual Reliability Needs Assessment (RNA)[132] that examines both resource and transmission needs over a ten year period. Resources totaling approximately 930 MW as well as transmission upgrades that are under construction or otherwise have met the screening criteria are included in the base case. The RNA determined that sufficient statewide resources are available to meet NPCC LOLE criteria through the year 2010. For 2011, the RNA indicates that sufficient resources would exist if 250 MW were added to New York City (NYC) or 500 MW were added in the Lower Hudson Valley or if transfer limits into NYC were increased. Beyond 2011, additional resources of between 1,750 MW and 2,000 MW would be needed to meet the criteria through 2016. A majority of those resources would need to be in the NYC zone.

Subsequent to the RNA, the NYISO solicits solutions to address the needs identified in the RNA. Sufficient market solutions as well as updated Transmission Owner (TOs) plans have been proposed to more than meet the needs through 2016. If sufficient market solutions are not proposed, the responsible TOs are obligated under the NYISO reliability planning process to implement regulatory backstops and/or gap solutions to meet any potential reliability shortfalls.

Although, deliverability of resources is evaluated in the NYISO's resource adequacy and planning studies both on an inter-area, as well, as intra-zonal basis, the NYISO currently has under development a deliverability test for new resources. This test would become part of the

[132] NYISO Report titled "Comprehensive Reliability Planning Process (CRPP) – 2007 Reliability Needs Assessment", March 16, 2007

NYISO's interconnection process. Resources that were not fully deliverable based on the test would either need to upgrade the system to be eligible for full capacity payments or only would be eligible to receive capacity payments for the portion of the facility that was deliverable.

The NYISO also depends on demand response to meet its resource adequacy requirements. Special Case Resources (SCRs) are one of the NYISO demand response programs that are counted as installed capacity resources. SCRs include loads that are capable of being interrupted and distributed generation that can be activated on demand. The table below shows proposed resource additions by class year.

Table: NYCA Proposed Resource Additions

ADDITIONS

As of April 1, 2007

OWNER / OPERATOR	STATION UNIT	ZONE	DATE	Name Plate Rating (kW)	*CAPABILITY (kW)* SUMMER (1)	WINTER (1)	UNIT TYPE	RNA
Proposed Resource Additions								
	Completed Class Year Study							
Windfarm Prattsburgh, LLC	Prattsburgh Wind Park	C	2007/11	55,500	5,550	16,650	Wind Turbines	
ECOGEN, LLC	Prattsburgh Wind Farm	C	2008/06	79,500	7,950	23,850	Wind Turbines	
NYC Energy LLC	NYC Energy LLC	J	2008/Q4	79,900	79,900	79,900	Combustion Turbine(s)	
Besicorp-Empire Power Co., LLC	Empire State Newsprint	F	2009/Q4	660,000	660,000	660,000	Combined Cycle	
SCS Energy, LLC	Astoria Energy (Phase 2)	J	2010/05	500,000	500,000	500,000	Combined Cycle	(2)
Calpine Eastern Corporation	CPN 3rd Turbine, Inc. (JFK)	J	2010	45,000	45,000	45,000	Combustion Turbine(s)	
Fortistar-Lockport Merchant	Lockport II Gen Station	A	2010	79,900	79,900	79,900	Combustion Turbine(s)	
	Class 2006 Projects							
Airtricity Developments, LLC	Munnsville	E	2007/08	40,000	4,000	12,000	Wind Turbines	
Noble Environmental Power, LLC	Clinton Windfield	D	2007/12	80,000	8,000	24,000	Wind Turbines	
Noble Environmental Power, LLC	Bliss Windfield	A	2007/12	72,000	7,200	21,600	Wind Turbines	
Noble Environmental Power, LLC	Altona Windfield	D	2007/12	99,000	9,900	29,700	Wind Turbines	
Noble Environmental Power, LLC	Ellenburg Windfield	D	2007/12	79,500	7,950	23,850	Wind Turbines	
UPC Wind Management, LLC	Canandaigua Wind Farm	C	2007/Q4	82,500	8,250	24,750	Wind Turbines	
Invenergy Wind, LLC	High Sheldon Windfarm	C	2008	129,000	12,900	38,700	Wind Turbines	
NY Windpower, LLC	West Hill Windfarm	E	2008/Q3	40,000	4,000	12,000	Wind Turbines	
PPM Energy/Atlantic Renewable	Fairfield Wind Project	E	2008/10	120,000	12,000	36,000	Wind Turbines	
Community Energy	Jordanville Wind	E	2008/Q4	150,000	15,000	45,000	Wind Turbines	
Fortistar, LLC	Fortistar VP	J	2008/Q4	79,900	79,900	79,900	Combustion Turbine(s)	
Fortistar, LLC	Fortistar VAN	J	2008/Q4	79,900	79,900	79,900	Combustion Turbine(s)	
Marble River, LLC	Marble River Wind Farm	D	2008/Q4	84,000	8,400	25,200	Wind Turbines	
Marble River, LLC	Marble River II Wind Farm	D	2008/Q4	134,000	13,400	40,200	Wind Turbines	
PSEG Power In-City I, LLC	Cross Hudson Project	J	2008/2009	550,000	550,000	550,000	Combined Cycle	
Caithness Long Island, LLC	Caithness Long Island	K	2009/Q2	310,000	310,000	310,000	Combined Cycle	(2)
KeySpan Energy, Inc.	Spagnoli Road CC Unit	K	2009/06	250,000	250,000	250,000	Combined Cycle	
TransGas Energy, LLC	TransGas Energy	J	2012/Q3	1,100,000	1,100,000	1,100,000	Combined Cycle	
	Class 2007 Projects							
Noble Environmental Power, LLC	Wethersfield Windfield 230kV	C	2007/12	129,000	12,900	38,700	Wind Turbines	
Noble Environmental Power, LLC	Clinton II Windfield	D	2007/12	21,000	2,100	4,200	Wind Turbines	
Noble Environmental Power, LLC	Bliss II Windfield	A	2007/12	30,000	3,000	9,000	Wind Turbines	
Everpower Global	Howard Wind	C	2007/12	62,500	6,250	18,750	Wind Turbines	
UPC Wind Management, LLC	Canandaigua II	C	2007/Q4	42,500	4,250	12,750	Wind Turbines	
Noble Environmental Power, LLC	Ellenburg II Windfield	D	2008/12	22,500	2,250	6,750	Wind Turbines	
Noble Environmental Power, LLC	Chateaugay Windpark	D	2008/12	100,000	10,000	30,000	Wind Turbines	
AES New York Wind, LLC	St. Lawrence Wind Farm	E	2008/12	130,000	13,000	39,000	Wind Turbines	
PPM Energy, Inc.	Clayton Wind	E	2008/12	126,000	12,600	37,800	Wind Turbines	
Dairy Hills Wind Farm, LLC	Dairy Hills Wind Farm	C	2009-2011	132,000	13,200	39,600	Wind Turbines	
				Total	**3,938,650**	**4,344,650**		

Notes:

(1) The above capability values for wind generation projects reflect expected values of 10% of Name Plate for summer capability and 30% of Name Plate for winter capability.

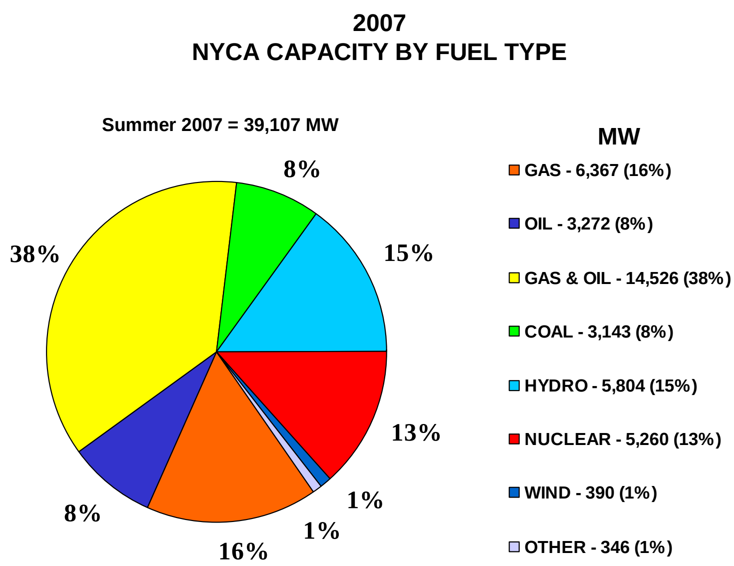
(2) Projects that have met the criteria for inclusion in the Base Case for the NYISO Reliability needs Assessment.

ns

Fuel Supply and Delivery

The following figure depicts New York's resource capacity mix by fuel type for the year 2007 on an installed capacity basis.

2007 NYCA Capacity by Fuel Type



Planned Resource[133] Capacity Mix by Year

Planned Resource Capacity Mix By Year								
Month Of July	Coal %	Gas & Oil %	Gas Only %	Hydro %	Nuclear %	Oil Only %	Wind %	Other %
2007	8.0%	37.1%	16.3%	14.8%	13.4%	8.4%	1.0%	0.9%
2008	7.1%	37.5%	16.4%	15.1%	13.6%	8.4%	1.0%	0.9%
2009	7.0%	38.0%	16.3%	15.0%	13.5%	8.4%	1.0%	0.9%
2010	7.1%	37.3%	16.4%	15.2%	13.6%	8.5%	1.0%	0.9%
2011	7.1%	37.3%	16.4%	15.2%	13.6%	8.5%	1.0%	0.9%
2012	7.1%	37.3%	16.4%	15.2%	13.6%	8.5%	1.0%	0.9%
2013	7.1%	37.3%	16.4%	15.2%	13.6%	8.5%	1.0%	0.9%
2014	7.1%	37.3%	16.4%	15.2%	13.6%	8.5%	1.0%	0.9%
2015	7.1%	37.3%	16.4%	15.2%	13.6%	8.5%	1.0%	0.9%
2016	7.1%	37.3%	16.4%	15.2%	13.6%	8.5%	1.0%	0.9%

[133] Only proposed resource additions included in the NYISO Reliability Needs Assessment (RNA), identified on the previous page, are included in this table.

The above table shows the projected installed capacity resource mix from 2007 through 2016. The "other" category includes resource recovery, wood burning, and other fuels. For the next five years, resources fueled by natural gas and wind will meet all of the growth in projected energy consumption.

There is a potential for a natural gas shortage in New York State 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 requiring operation such that the loss of a single gas facility (referring to a pipeline or storage facility) does not result in the loss of electric load within the New York City and Long Island zones:

> **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 does not result in the loss of electric load within the New York City and Long Island zones."**

The 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 MWs 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, there is sufficient generation in the low to moderate fuel risk categories 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.

New York's Governor Spitzer has announced a goal to reduce energy consumption in New York by 15 percent of forecasted levels by the year 2015. The New York PSC is examining alternatives for implementation of reduction of energy usage, and the implementation of this initiative would also affect the future capacity needs of New York State.

The NYISO continues to monitor the progress of this proceeding and the achievement of the New York's energy efficiency goals to determine their impact on bulk power system reliability.

The NYISO continues to work with regulators and other interested parties on a host of environmental initiatives aimed at encouraging the development of new cleaner generation and reducing emissions from existing generation. The four programs with the potential to have the most impact on the power sector are; The New York State Renewable Portfolio Standard (RPS), NOx Emission Reduction of the Ozone Transport Commission, New York State Consent Orders, and the Regional Greenhouse Gas Initiative. A complete description of these initiatives is included in NYISO's Power Trends document, dated May 2007[134].

The effects of the RPS and Consent orders are captured in the above forecasts for resources in new plants and retirements, respectively. Plans are currently being developed to address compliance in New York for the other two mentioned initiatives.

Transmission Assessment

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 2016.

Significant transmission projects currently being proposed include the following:

Area	Project Name	Status	In-Service Date
PJM-NY	Atlantic Energy Project Neptune – 660/750 MW monopole DC from PJM to Newbridge Rd. LI	C	2007
PJM-NY	East Coast Power – 300 MW Linden VFT Inter-Tie	S	2008
NE/NY	Replace Norwalk Harbor - Northport cable	S	2008
NY	RG&E Upgrades - 4th Station 80 345/115 kV Transformer and Other Upgrades	S	2008
NY	Mott Haven 345 kV Substation	S	2007
NY	Sprainbrook-Sherman Creek 345 kV	S	2009

Status:
S – Study is underway or complete
C – Under construction

Operational Issues

No unusual operational issues have been identified for the period 2007-2016.

Ontario

The province of Ontario covers an area of 1,000,000 square kilometers (415,000 square miles) with a population of 12 million. The Independent Electricity System Operator (IESO) directs the operations of the IESO-controlled grid (ICG) and administers the electricity market in Ontario. The ICG experiences its peak demand during the summer, although winter peaks still remain strong.

Peak Demand and Energy

The actual summer peak demand for 2006 was 27,005 megawatts (MW), which is 5.9 percent higher than the normal weather peak demand forecast of 25,502 MW in the previous report. The actual winter peak for 2006/2007 was 23,935 MW, or 3.9 percent lower than the 24,897 MW normal weather forecasts in the previous report.

[134] http://www.nyiso.com/public/webdocs/newsroom/whats_new/nyiso_ptrends07_final.pdf

Cooling load growth, combined with minimal growth in heating load has led to the transition from winter peaking to dual peaking to summer peaking over the last 10 years. Going forward conservation and demand management (CDM) programs will blunt much of the load growth, however Ontario is expected to remain summer peaking.

Based on committed plans for aggressive CDM programs, the summer peak demand is forecast to contract at an annual average rate of 0.2 percent. The winter peak is expected to contract at an annual average rate of 0.7 percent over the forecast. Without these programs, annual peak summer demand would be expected to grow by 0.7 percent per year. Resource adequacy plans are being developed to retain flexibility to balance new generation procurement and existing generation retirement with CDM plans, in the event any programs exceed target levels or fall below target.

The Independent Electricity System Operator (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.

Actual Ontario energy demand for 2006 was 151.1 terawatt hours (TWh). This was 2.9 percent lower than last year’s forecast for 2006. The aforementioned conservation programs coupled with slower economic growth translates into a lower projection of energy demand than last year. Over the forecast, energy demand is expected to grow by 0.4 percent per annum. Overall electricity energy demand is expected to increase while conservation, load shifting and demand response programs are expected to influence declines in the summer and winter peaks.

Resource Adequacy Assessment

Under median demand growth assumptions, resources that are currently available within Ontario together with the forecast new generation and economic imports are sufficient to meet the NPCC regional resource adequacy criterion, from 2007 to 2016.

More than 500 MW of new supply was added to the IESO-controlled grid in 2006. The new supply included 117 MW of gas-fired generation, 395 MW of wind, 22 MW from upgrades to existing generators, four MW of hydro and two MW of generation from biomass. Since the beginning of this year, 25 MW of new generation consisting of 20 MW of hydro and five MW from landfill gas has been added.

Provincial government directives and procurements by the Ontario Power Authority (OPA) will bring 6,800 MW into service over the 10 year period to meet demand. Halton Hills Generating Station (600 MW, gas-fired) and seven Combined Heat and Power (CHP) projects with the total capacity of 414 MW were contracted by OPA since the previous Long-Term Reliability Assessment in 2006.

New or refurbished generation capacity (seasonally adjusted), that is committed or planned in the next 10 years, comprises the following:

Nuclear	1,594 MW
Natural Gas	3,853 MW
CHP	414 MW
Hydro	307 MW
Wind	707 MW
Total	6,875 MW

The planned shut down of Ontario's coal-fired generating stations is being managed by the OPA and the IESO. The schedule for retirements is part of OPA's integrated power system plan (IPSP) that was filed recently with the Ontario Energy Board, (OEB) and will take place by 2014 under provincial regulation. In 2006, generation from coal-fired facilities was down three percent from the previous year. As new facilities come into service and CDM activities progress, reliance on coal to meet demand in Ontario can continue to decline, and ultimately lead to shut down in 2014.

IESO adequacy assessments include only those projects that are under construction or that have power supply contracts with the OPA. Additional demand measures and supply additions are identified as part of the IPSP and will be included as future resources once contractual arrangements are in place. The IESO target is an available reserve margin this year of about 16 percent (15.6 percent to be precise for July, 2007) above the summer peak demand based on monthly normalized weather impacts. The IESO does not include imports (up to 4,000 MW capability) or the use of emergency operating procedures (about 900 MW from voltage reduction, public appeals and emergency load reduction programs) in assessing supply against this requirement. The IESO does assume fossil generation temperature deratings, wind deratings (90 percent) and hydroelectric water limitations, all three of which total about 3,300 MW. Planned outages are permitted only if reserve margins allow, in which case their impacts are assessed as well.

OPA has responsibility for long-term supply, integrated power system planning and development of conservation and demand related measures. This assignment of responsibilities has been implemented by the Province to provide assurance of adequate future electricity supply for Ontario. The OPA's first integrated power system plan (IPSP) was filed in August 2007 with the Ontario Energy Board for their approval. The IPSP will address Ontario electricity needs for the next 20 years. Generation deliverability to load under normal system conditions is not currently a serious issue in Ontario, although some generation congestion occurs intermittently and some load areas are at or near the capacity of local transmission facilities at peak times. Future generation deliverability and transmission supply into growing load areas will be managed as part of OPA's IPSP.

No fuel delivery interruptions are anticipated for coal, nuclear and gas generators.

Resources available within Ontario are generally expected to be adequate, but deficiencies could arise as a result of higher than forecast generator outages, prolonged extreme weather conditions and other influencing factors. Available imports, to supplement internal generation, are expected to be sufficient to meet the Ontario demand under these circumstances.

Ontario's Market Rules currently restrict the external commitment of Ontario generation capacity. Similarly, imports to Ontario are not considered to be capacity commitments.

There are environmental restrictions placed on the thermal effluent from nuclear, fossil and gas plants, opacity from fossil units and minimum/maximum flow at hydro plants. Procedures are in place for generators to seek environmental variances from government ministries at the request of IESO when required for reliability.

Fuel Supply & Delivery

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 is establishing communication protocols and a framework for contingency analysis in order to manage operational and reliability issues in both energy sectors.

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

Weather has an effect on fuel supply in three main areas. Hydroelectric energy typically declines under hot dry conditions experienced in the summer. Coal-handling facilities at individual stations occasionally experience difficulties under extreme winter conditions. Gas-fired generation may be limited if the availability of natural gas supplies is reduced over winter peak periods due to fuel arbitrage opportunities or due to tight supply condition impacts on interruptible gas contracts. The IESO includes median estimates of these impacts based on statistical analysis of gas-fired generation operational patterns over winter periods since market opening.

Transmission Assessment

During the last year, deratings on the 500/230 kilovolt (kV), 750 MVA autotransformers at Trafalgar TS were removed and the Great Lakes Power transmission reinforcement was completed.

Imports from New York continued to be limited at times by transmission constraints internal to Ontario during the summer of 2006. These limitations are anticipated to continue in 2007 until the completion of the new 230 kV double circuit line between Allanburg TS and Middleport TS which will result in an increase in the Queenston Flow West capability of 800 MW. New York transfers into Ontario will still be limited by the interconnections to New York, but should see a net increase in transfer capability of about 350 MW. Most of the project work has been done but its full completion has been delayed by a land ownership dispute.

Hydro One and TransÉnergie are building a 1,250 MW interconnection between Hawthorne TS in Ontario and Outaouais station in Quebec consisting of a double circuit 230 kV line and back-to-back high-voltage direct-current (HVdc) converters. Work to accommodate the tie, scheduled to be in service in 2009, will also include improvements to the supply to stations in the Ottawa area.

The existing special protection system (SPS) at St. Lawrence was modified, allowing increased westward transfers. This SPS, which rejects generation at Saunders GS for circuit contingencies between eastern Ontario and the Toronto area, is planned to be enhanced further, to increase its functionality and reliability under peak load conditions, and to maximize simultaneous import capability from Hydro Québec and New York. These future enhancements will be required in 2009 upon completion of the new 1250 MW Ontario-Québec interconnection.

High loop flows continue to be present through the Ontario system. Phase shifters have been installed by Hydro One in Ontario to mitigate the problems caused by the loop flows affecting Ontario's most heavily used interfaces. This equipment cannot be used as intended until IESO and the Midwest Independent System Operator (Midwest ISO) complete a corresponding operating agreement, which is currently awaiting negotiations between Hydro One and the International Transmission Company.

Significant congestion of imports from the Michigan direction in 2005 prompted the IESO to seek temporary solutions until the negotiation between Hydro One and ITC conclude. The phase angle regulators (PARs) on the Michigan - Ontario interconnection have been operated in a by-passed mode since the beginning of 2006. Before summer 2006, the IESO, the Midwest ISO, Hydro One and International Transmission Company agreed to temporarily bypass the PARs for normal operation until an agreement is reached to make full use of their regulating capability. Bypassing the PARs increases Ontario's transfer capability to and from Michigan by 300 to 350 MW in the summer and by about 400 MW in the winter.

Over the next decade, the need for transmission enhancements is particularly evident in three areas of the Ontario:

- In southwestern Ontario to deliver additional nuclear and wind supply from the Bruce area,
- In the northeast and northwest to enable the planned expansion of hydroelectric and wind capability and to reinforce the connection of these areas to the load centre in southern Ontario
- In the Toronto region in order to meet capacity needs of fast growing areas in the Greater Toronto Area and to improve reliability to Canada's largest city.

The southwestern Ontario transmission system needs to be enhanced to deliver the planned and future increases in generating capability in and around the Bruce peninsula. Currently, there is inadequate transmission out of the Bruce area to accommodate both the expected wind developments in that area and the expanded capacity of the Bruce nuclear station resulting from planned refurbishments. Some near-term reinforcements include the up-rating of the Hanover to Orangeville 230 kV circuits, and the installation of additional voltage support facilities at various transmission stations in southwestern Ontario. These will increase the transfer capability out of Bruce in the short-term. Hydro One has submitted a leave-to-construct application to the Ontario Energy Board for a new 500 kV double-circuit line from Bruce to Milton. The line will provide the required transmission capability over the long-term to deliver the full capability of the Bruce refurbishment and both planned and potential new renewable resources in the Bruce area. The new 500 kV line out of the Bruce area is required as soon as possible to accommodate the additional generation from both new wind projects and refurbished Bruce nuclear units. To minimize potential congestion costs, interim measures, that could begin as early as 2009, are being assessed. These measures include the use of generation rejection of Bruce units and wind turbines, 30 percent series compensation of the existing 500 kV lines between Bruce, Longwood and Nanticoke, and restricting further generation development in the Bruce area, in addition to the near-term reinforcements described above. These measures are not substitutes for a new line, as they will not eliminate congestion and will increase the operational complexity of this part of the transmission system, and will stretch its design capability. However these measures are expected to reduce the amount of congestion until a new line is built.

As the Nanticoke coal-fired station is phased out by 2014, additional voltage support in southwestern Ontario will be required. Both static and dynamic reactive power solutions are being considered, ranging from shunt capacitors to possible replacement generation.

Over the next few years, over 1,600 MW of contracted gas-fired generation will be coming in-service in the Sarnia area. This will significantly increase the amount of power flowing between the Sarnia area and the London area and stress the existing transmission system west of London. The planned closure of the Lambton coal-fired generating plant (2,000 MW) early next decade, however, will reduce this transmission concern. Thus, there is currently no plan to reinforce the transmission west of London. This need will be monitored into the future as new generating resources such as renewables and combined heat and power projects are proposed in the Sarnia and Windsor-Essex areas.

Transmission enhancements in the northeastern part of the Ontario grid are required to allow the delivery of planned generation from that area to southern Ontario. The proposed enhancements, including series capacitors at Nobel TS, and a static var compensator (SVC) in northeastern Ontario, are expected to relieve existing congestion and accommodate the additional output from the proposed expansion of the four existing hydroelectric stations on the Lower Mattagami River and other committed renewable energy developments in northeastern Ontario.

The development of enabling transmission reinforcements is planned to integrate additional renewable resources procured in the northern parts of Ontario and to connect these areas to the load centre in southern Ontario.

The continuous economic growth experienced in parts of Ontario in the last decade has resulted in the loads in a number of areas reaching or exceeding the capability of the existing transformer stations and/or their supply lines. Some large load centers also have concerns with supply security. To address these needs and provide additional local area supply capacity for future load growth, work has commenced on a number of area supply projects, two of which are highlighted below.

The central Toronto area is currently served through two transmission paths into the area. A third supply path is expected to be required in the next decade in order to maintain long-term reliability and to provide a diversity of supply paths into the city. New generation, conservation and demand measures in the near-term will help to mitigate some of the impacts if one of the supply paths is lost.

In the York Region, north of Toronto, the transformer station capacity has been exceeded due to the rapidly growing loads in the Newmarket and Aurora area. There is an immediate need for a new transformer station in the area. Plans are underway to have a new transformer station in service before the end of 2008 to address the immediate needs. Longer term, transmission constraints are expected to occur as early as 2011. Local generation proposed by the OPA is expected to alleviate these constraints but work to procure this generation must begin soon.

The IESO conducts Interregional Transmission Transfer Capability studies and participates in regional and interregional studies to ensure adequate import and export transfer capability exists.

Operational Issues

Ontario's import failure rate[135] has decreased since the implementation of the Day Ahead Commitment Process (DACP) in June 2006. The Emergency Load Reduction Program (ELRP), which provides incentives to loads to reduce their energy usage under stressed system conditions, was also introduced in June 2006.

In 2007, the IESO is planning to start dispatching two additional OPA contracted demand response programs. In addition to the current voluntary peak reduction program, these consist of an obligatory load-shifting program and an obligatory peak-reduction program. Discussions are also underway with the NYISO and the Midwest ISO for improving the interchange scheduling protocols.

At present, the installed wind capacity in Ontario is 395 MW. More than 700 MW of wind capacity will come into service in the next two years, of which 10 percent is counted as capacity contribution. The IESO is working with the results from studies it co-sponsored on the potential contribution of wind in meeting the province's future power needs. These studies, together with growing experience with operational wind farms in Ontario and further study underway will form the basis for necessary changes to operational processes to integrate new wind facilities. The IESO sponsors the Ontario Wind Power Integration Working Group to identify issues and assist with their resolution. Working group materials, public study reports and wind statistics are posted on the IESO web. Operational requirements are documented in IESO Market Rules or Market Manuals.

The 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 black start tests.

References

The IESO publishes its 18-Month Outlook in the last month of every quarter. The 18-Month Outlook provides an assessment of the reliability of the Ontario electricity system for the next 18-Month period. The 18-Month Outlook is intended for operational planning purposes and for the scheduling of generator outage plans.

The Ontario Reliability Outlook is published semi-annually to report on progress of the generation, transmission and demand management projects underway to meet future reliability requirements.

These reports are posted on the IESO web.[136] With information concerning the OPA's IPSP and related discussion papers[137] available as well. The IESO wind studies are posted[138] under the heading "Studies". The two studies referenced are:

- "*An Analysis of the Impacts of Large-Scale Wind Generation on the Ontario Electricity System*" by AWS Truewind for Canadian Wind Energy Association (CanWEA) and IESO
- *"Ontario Wind Integration Study"* by General Electric International, Inc and AWS True

[135] An import failure occurs when day ahead or hourly planned imports fail to clear both the Ontario market and the external markets in time for real-time operations. In these cases replacement supply must be activated, often from operating reserves, recallable exports, surplus resources or dispatchable loads. On some occasions Emergency Load Response, Emergency Energy purchases or other control actions must be used.

[136] http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp

[137] http://www.powerauthority.on.ca/ipsp/

[138] http://www.ieso.ca/imoweb/marketdata/windPower.asp

Québec

Peak Demand and Energy

The Québec Area is a winter-peaking network due to the fact that more than 70 percent of the households use electricity for space heating.

The actual winter peak demand for 2006-2007 was 36,251 MW, which was about 230 MW lower than the normal weather forecast of 36,479 MW presented in the previous report of the RAS.

For the 2007-2008 winter period, the forecast peak demand has been established at 36,539 MW, which is 265 MW lower when compared with last year's forecast for the same period. Through the 2009-2010 winter period, the peak load forecast has been revised downward by 100 MW to 300 MW. This change is principally due to a downward revision of the short term economic forecast in the manufacturing sector and the closing of certain industrial loads such as sawmills and paper mills.

For the long term, these negative impacts on demand are counterbalanced by a solid demand growth in the residential and commercial sectors. In 2016-2017, the winter peak demand forecast is 38,748 MW. The winter peak demand is expected to grow at an annual rate of 0.7 percent (10-year period). This is slightly higher than last year's forecast (0.6 percent).

For the winter 2006-2007, Québec has industrial interruptible load contracts which account for a maximum of 1,265 MW. These contracts are expected to be renewed during the entire study period.

The actual Québec energy demand for 2006 was 185.8 TWh. This was 3.2 percent (or 6.2 TWh) lower than last year's forecast for 2006. More than 70 percent (4.5 TWh) of this variation is due to climatic conditions during the year 2006, especially in the winter period, which realized warmer than normal weather.

For 2007, the energy demand forecast, under normal weather conditions, is 191.6 TWh. When compared to actual energy demand for 2006, and adjusted for weather conditions, the 2007 energy demand forecast is higher by only 1.2 TWh (or 0.6 percent). This increase is consistent with the ten-year compounded annual average growth rate forecast of 0.7 percent.

Weather and economic assumptions - The forecasts present in this report are based on normal weather assumptions over a 30-year span of historical weather conditions. No change has occurred in the normalization procedure since last year. The forecasts are also based on a certain number of economic, demographic and energy-use assumptions. These assumptions were presented in the second follow-up of the Hydro-Québec Distribution (HQD) Procurement Plan submitted to the Québec Energy Board in October 2006. Since last year's report, the major change comes from the downward revision of economic growth, especially in the manufacturing sector.

Load forecast uncertainty - Load forecast uncertainty is a measure of the possible outcome of the load, given that the variables that impact the load are uncertain. It is due to load sensitivity to weather conditions and to uncertainty caused mainly by the evolution of economic and demographic parameters affecting load demand.

To quantify weather uncertainty and its impacts on peak demand, Hydro-Québec has developed a method that uses hourly chronological load profiles based on 30-year historic weather conditions (1971-2000). Since Québec has a winter peaking load profile, the uncertainty, measured by a standard deviation analysis, is lower during the summer than during the winter. As an example, at the time of the summer peak, the uncertainty in load contributed by weather conditions is about 300 MW, equivalent to one standard deviation. During winter, this uncertainty is approximately 1,200 MW.

Uncertainty related to load forecast is evaluated with Monte Carlo simulation where economic parameters are generated for different possible outcomes. For each year of the forecast horizon, a distribution of probability of all possible demand forecasts is generated. For example, load forecast uncertainty, measured by one standard deviation, for one year after the forecast is about 3.5 TWh (full year).

Resource Adequacy Assessment

In the “2006 Québec Area Interim Review of Resource Adequacy,” Québec demonstrated that the installed reserve margin requirement, expressed as a percentage of the peak load, needs to be slightly above 10 percent to comply with the NPCC adequacy criterion. In this long term assessment, the planned reserves are close to 14 percent except for the period of time during which the Gentilly 2 nuclear unit will be out of service for refurbishment. The installed reserve margin percentage will be between 12 percent and 13 percent during the Gentilly outage. In the case of a high load forecast scenario, Québec still meets the NPCC resource adequacy criterion (LOLE less than 0.1 day per year).

In terms of projected capacity and reserve margins, there is no significant change from last year’s NERC assessment.

From January 2007 to January 2017, Québec hydroelectric capacity will increase by 2,550 MW (new and upgraded hydro generation plants). By January 2016, the installed wind power capacity will increase by 3,000 MW, to reach a total of 3,500 MW. The wind power is completely derated in this study. The overhaul of the nuclear station Gentilly 2 is planned from March 2011 to October 2012.

Until October 2011, there is a firm purchase of 200 MW from the Maritimes Area with firm transmission. Hydro-Québec Production has firm export commitments of 455 MW to neighbouring networks outside Québec until October of 2012. These capacity sales will decrease gradually to 151 MW in October of 2017.

In this study, Québec’s energy efficiency programs are taken into account through a reduction of load forecast (about 250 MW at the 2006/2007 peak forecast to 1,250 MW at the 2014 winter peak). Also, there are some direct control load management and interruptible load programs accounting for 1,500 MW throughout the whole study period.

Fuel Supply and Delivery

Québec's energy supply is largely coming from hydro generating stations (93 percent), located on different river systems geographically distributed, the major ones with multiyear storage capability.

In order to demonstrate its energy reliability Hydro-Québec presents an energy reliability assessment to the Québec Energy Board three times a year. Hydro-Québec Production is the generation division of Hydro-Québec and Hydro-Québec's reservoirs' manager. Its energy reliability criterion states that Hydro-Québec Production must maintain a sufficient energy reserve to protect against a possible hydraulic deficit of 64 TWh in two consecutive years and 98 TWh in four consecutive years.

The last assessment produced by Hydro-Québec for the Québec Energy Board shows that Hydro-Québec Production complies with this energy reliability criterion.

Regarding the thermal units, each has on-site fuel storage that can be refuelled by truck or by barge. The new gas-fired combined-cycle plant has a firm natural gas supply contract for the first five years of operation.

Transmission Assessment

Since last year, only a few projects have been commissioned in service on the Québec system. These projects have no impact on system transfer capacity.

Interconnection transmission capability studies are conducted periodically with Québec's neighbouring systems to assess interconnection limits. Due to the possible retirement of the Monroe HVDC converter (existing Des Cantons – Monroe HVDC interconnection), HQTE is evaluating the feasibility of operation of the Des Cantons converter with the Sandy Pond converter (this is a new DC configuration). Also, to increase the exchange capability between the Québec and the Ontario system, a new interconnection of 1250 MW is planned to be in service in 2009 with reinforcement planned in 2010 by a new 315 kV double circuit line in the Outaouais subsystem.

During the next ten years, about 550 miles of new lines will be added on the Hydro-Québec TransÉnergie grid. The major projects in this planning horizon are:

- New transmission lines and local equipment enhancements to integrate additional generation provided by hydroelectric projects (Péribonka 2008, Rapides-des-Cœurs 2008, Chute-Allard 2008, Eastmain 1A 2011 and Sarcelle 2011) to the main grid;
- Few changes and new transmission lines on the Gaspesia subsystem will be made to integrate new wind power generation. This subsystem will be reinforced to integrate around 1500 MW of wind generation.

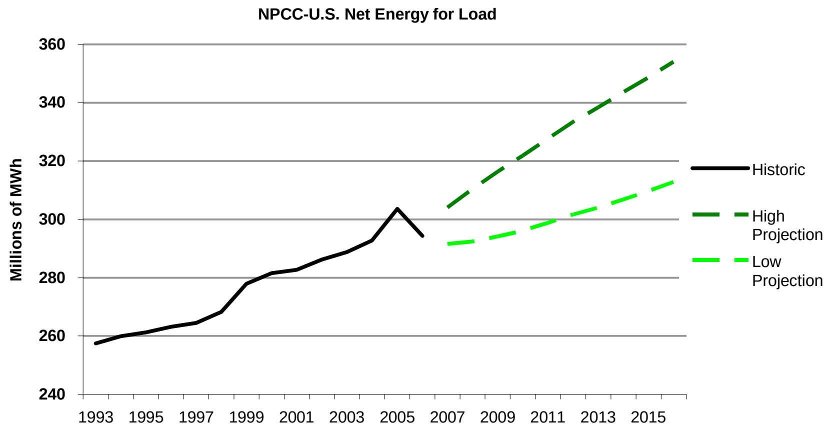
Operational Issues

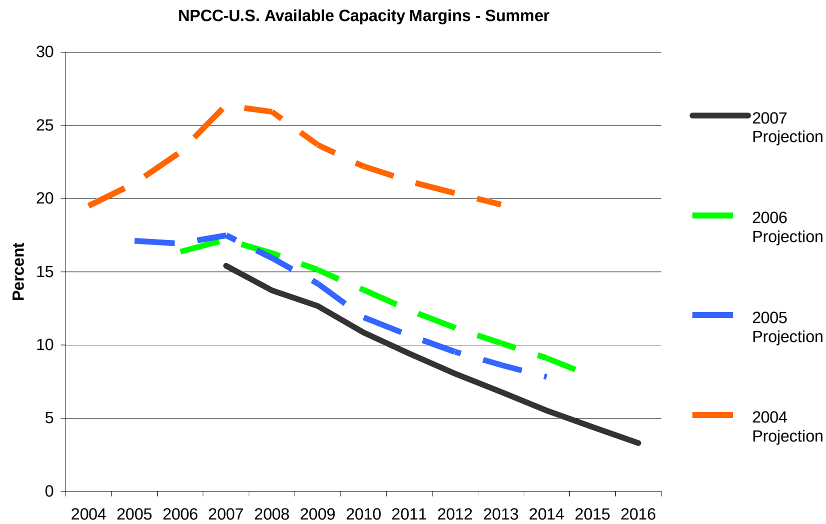
No unusual operational issues have been identified for the period 2007–2016.

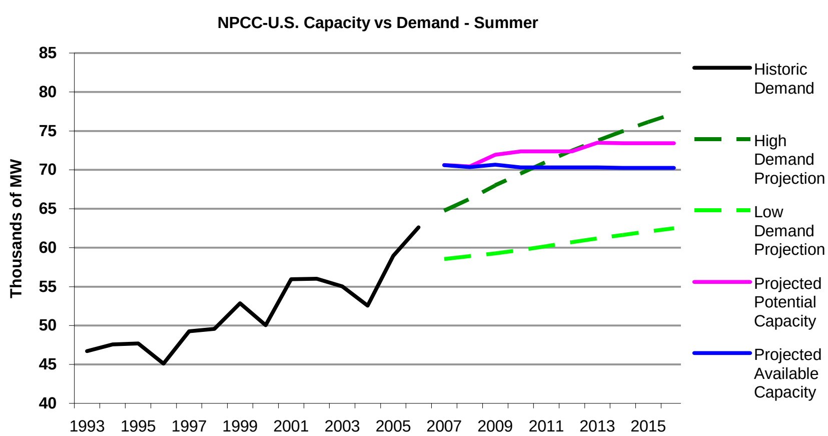
Region Description

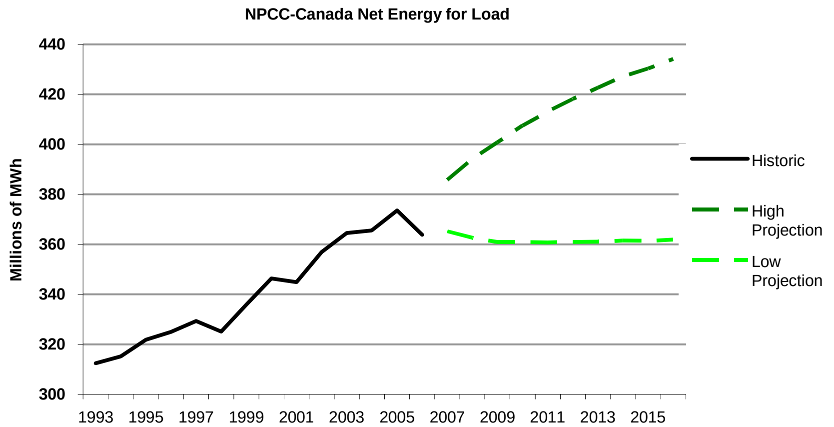
The Northeast Power Coordinating Council, Inc. (NPCC) is the cross-border regional entity and criteria services corporation for Northeastern North America. It is the NPCC mission to promote and enhance the reliable and efficient operation of the international, interconnected bulk power system in Northeastern North America pursuant to its agreement with the Electric Reliability Organization which designates NPCC as a regional entity and delegates authority from the U.S. Federal Energy Regulatory Commission, and by Memoranda of Understanding with applicable Canadian Provincial regulatory and/or governmental authorities. The geographic area covered includes New York, the six New England states, and Ontario, Quebec, and Maritime Provinces in Canada. The total population served is approximately 56 million, and the total geographic area is approximately 1 million square miles. NPCC was originally formed shortly after the 1965 Northeast Blackout to promote the reliability and efficiency of the interconnected power systems within its geographic area. Additional information can be found on the NPCC Web site (http://www.npcc.org/).

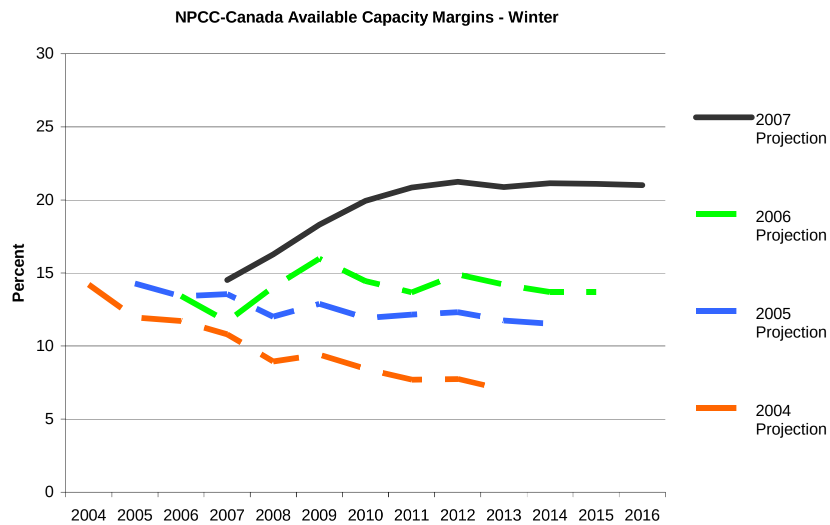
NPCC Capacity and Demand

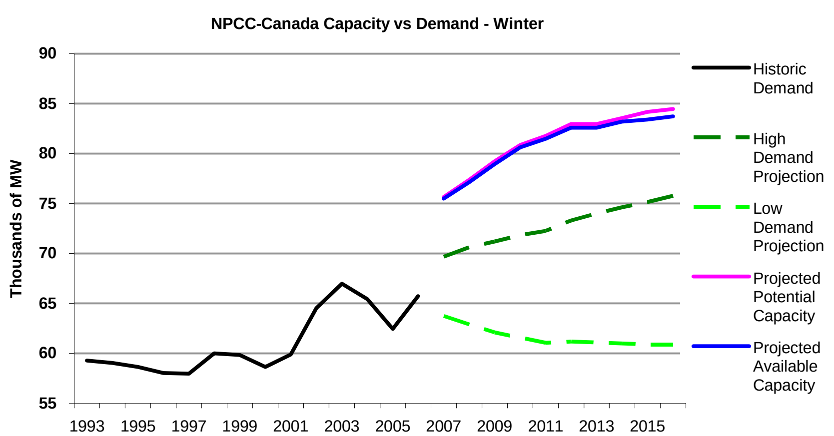




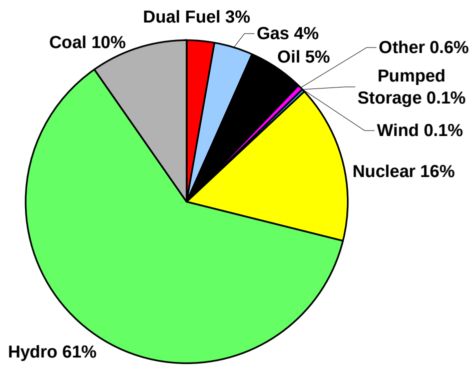



NPCC-Canada Net Energy for Load
Millions of MWh
440
420
400
380
360
340
320
300
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
Historic
High Projection
Low Projection

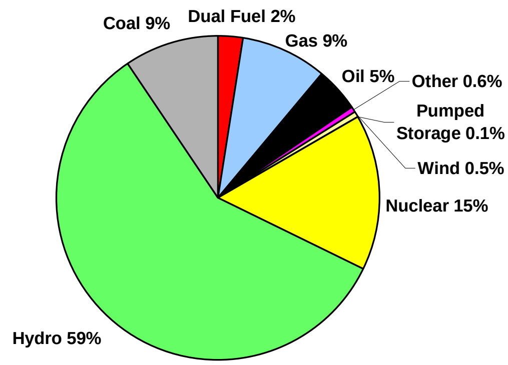

NPCC-Canada Available Capacity Margins - Winter
Percent
30
25
20
15
10
5
0
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2007 Projection
2006 Projection
2005 Projection
2004 Projection


NPCC-Canada Capacity vs Demand - Winter
Thousands of MW
90
85
80
75
70
65
60
55
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
Historic Demand
High Demand Projection
Low Demand Projection
Projected Potential Capacity
Projected Available Capacity

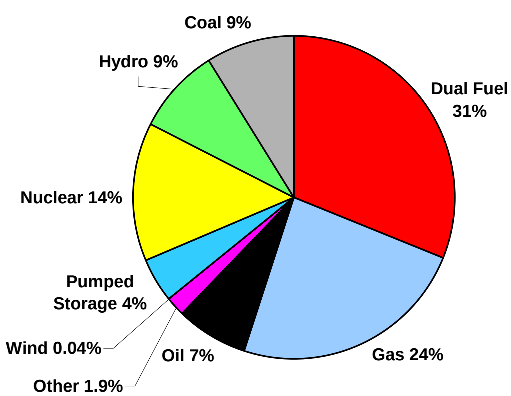
NPCC-Canada Capacity Fuel Mix 2006



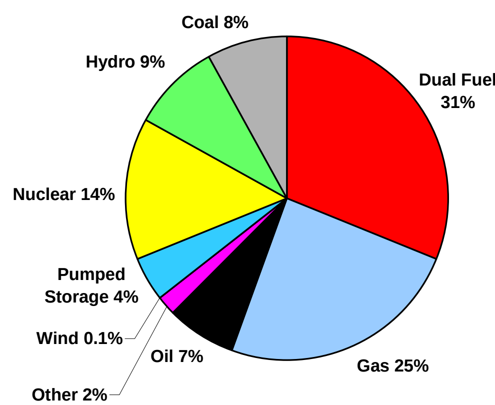
NPCC-Canada Capacity Fuel Mix 2012



NPCC-U.S. Capacity Fuel Mix 2006



NPCC-U.S. Capacity Fuel Mix 2012



RFC

Introduction

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

All RFC members are affiliated with either the Midwest ISO (MISO) or PJM Interconnection (PJM) as their regional transmission organization (RTO), except Ohio Valley Electric Corporation (OVEC), a generation and transmission utility with facilities in Indiana, Kentucky and Ohio. OVEC is not affiliated with either RTO, although OVEC's Reliability Coordinator services are performed by PJM.

Reliability*First* region does not have officially-designated subregions. About one-third of the RFC load is in MISO, with nearly all remaining load in PJM. Load in the OVEC Balancing Authority area is about 100 MW. From the perspective of the RTOs, approximately 60 percent of the MISO load and 87 percent of the PJM load is within RFC.

Effective January 1, 2007, E.ON U.S. and the City of Springfield, Illinois became members of the SERC region and are no longer a part of RFC. This assessment excludes E.ON U.S. and the City of Springfield information and data for the entire assessment period. This transfer to the SERC region has made it necessary to re-calculate the 2006 reserve margins for the RFC region for comparison to the reserve margins in this assessment. All references to 2006 actual and forecast data are based on the current Reliability*First* regional boundary, which excludes these two entities.

Within RFC, each individual company along with their RTO performs planning analyses for facility additions. Regional reliability assessments are performed by RFC based on those proposed additions or changes to generation capacity and transmission facilities in order to determine the adequacy of the existing and future bulk power system to serve projected load.

Peak Demand and Energy

Throughout the assessment period, the annual peak in the Reliability*First* region is expected to continue to occur during the summer. The coincident total internal demand is expected to be 184,200 MW in 2007 and 208,900 MW in 2016. Current resource projections developed by Reliability*First* members indicate that direct-controlled and interruptible load management programs will provide up to 3,900 MW of expected demand response load reduction at the time of the peak from 2007 through 2016. The effects of interruptible and demand-side management loads are included in Reliability*First*'s coincident net internal demand, projected to be 180,400 MW in 2007 and 205,300 MW in 2016. This is a 1.4 percent average annual load growth in net internal demand over the period 2007 through 2016, slightly less than the average growth rate of 1.6 percent in last year's projection. 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. This is demonstrated by the 2006 actual peak of 190,800 MW, which was 9,600 MW higher than the total internal demand forecast for 2006 due to the extreme temperature and humidity at the time of the peak.

An analysis of overall demand uncertainty and variability, and the variability in demand due to weather has not been conducted by Reliability*First* for the entire RFC area. Planning for such uncertainties is the responsibility of each individual load serving entity. However, experience shows that higher than average temperature and humidity can be expected to increase the summer peak demand by as much as 10,000 MW.

Resources

RFC has adopted a regional standard for resource adequacy of Loss of Load Expectation (LOLE) of one occurrence in ten years (see www.rfirst.org/committees/RFC_Approved_Standards.html). This standard will be implemented by a requirement to maintain a reserve margin determined from LOLE analyses. The studies to determine the reserve margins required by regional Load Serving Entities are scheduled for completion in 2007, with initial implementation in 2008. These studies will be conducted by groups of LSEs formed into entities known as Planned Reserve Sharing Groups (PRSGs). Beginning in 2008, regional assessments will include a review and report on the adequacy of each PRSG based on its reserve margin analysis. Until then, the target 15 percent reserve margin from the former MAAC region is being used as a benchmark to assess regional resource adequacy.

The potential net seasonal capability is projected to be about 222,400 MW by year end 2007. The total announced net increase in generating capacity from 2008 through 2016 is about 2,500 MW. This forecast does not include thousands of megawatts of “possible capacity additions” identified by the PJM and Midwest ISO generation interconnection queues.

Additionally, a significant amount of existing capacity is not counted toward meeting the reserve requirements because this capacity is not committed to serve regional load.

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 benchmark reserve margin. No purchases or sales after 2007 are included in the analysis, although some long term purchases and sales have been arranged. For example, PJM has reported a projected net import of 869 MW for the 2008-2016 period. Summer reserve margins in RFC range from a high of 23.3 percent in 2007, declining to 9.6 percent in 2016. These reserve margins are based on forecast net internal demand and potential capacity resources. The comparable reserve margins from the 2006 forecast declined from 22.1 percent in 2007 to 11.7 percent in 2015.

The amount of potential capacity resources is sufficient through 2012. These reserve margins include over 7,800 MW of projected capacity additions, and existing capacity that is currently categorized as energy-only or uncommitted capacity. Starting in 2013, additional capacity resources are needed to maintain an overall RFC target 15 percent reserve margin. The amount of needed capacity resources ranges from 1,500 MW in 2013 to 11,100 MW in 2016.

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 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. Reliability*First* 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.

About 48 percent of the existing capacity uses coal for its fuel. Another 15 percent of the capacity is nuclear fueled. Oil and natural gas fuels comprise 6 percent and 27 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

Plans for the next five years project the addition of about 444 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 these 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. Both MISO and PJM perform comprehensive generator and load deliverability studies.

A new 210-mile 500 kV RFC-SERC interconnection known as the Trans-Allegheny Interstate Line (TrAIL) project is scheduled for operation by 2011. The project consists of the following 500 kV circuits: 502 Junction to Mt. Storm, Mt. Storm to Meadow Brook, and Meadow Brook to Loudoun. This project will relieve anticipated overloads and voltage problems in the Washington, DC area, including anticipated overloads expected in 2012 on the existing 500 kV transmission facilities serving this critical load center. The five-year window before the existing facilities become overloaded presents a very challenging timeframe for the development, licensing and construction of this project.

Another new transmission project is the Potomac-Appalachian Transmission Highline (PATH) project. This project will include a new 250 mile 765 kV transmission line from the John Amos substation in western West Virginia to the Bedington substation in eastern West Virginia and two 40 mile 500 kV circuits will connect Bedington to a new substation in Kemptown near the Doubs-Brighton and Brighton-Conastone 500 kV lines outside of Washington, DC. Extended long-term analysis shows that this project, combined with the TrAIL project mentioned above, is very effective in relieving possible future overloads in Washington, DC, Pennsylvania, Maryland, West Virginia, Virginia and even New Jersey. This line also reduces the flow on the Kammer 765/500 kV transformer which was heavily overloaded in PJM future load deliverability studies (http://www.pjm.com/planning/rtep-baseline-reports/baseline-report.html). The expected in-service date is June 2012.

In northeastern RFC, a new 130 mile 500 kV transmission line from Susquehanna to Lackawanna in Pennsylvania, and on to Jefferson and ending at Roseland in northern New Jersey is planned. This line will resolve overloading problems on 23 existing facilities in Pennsylvania and New Jersey. The expected in–service date is June 2012.

Due to the planned retirement of the Oyster Creek nuclear plant coupled with a large export out of northern New Jersey in the post 2015 timeframe, additional reinforcements in New Jersey are being studied.

The Scott-Bunce Creek B3N circuit on the Michigan-Ontario interface is expected to be fully controlled by phase angle regulators (PARs) by the summer of 2009. Facility failures during the past few years have delayed the full operation of this circuit. A new PAR has been ordered for the B3N circuit in Michigan, and the transmission line on that circuit has been restored. An operational agreement is being negotiated. Until that agreement is in place, the existing PARs on the three other Michigan-Ontario tie lines may now be used for emergency conditions (e.g. if load shedding is pending or in a 5 percent voltage reduction case, etc.) if needed. The PARs are intended to improve the ability to manage power flow around Lake Erie.

A Static VAR Compensator (SVC) is planned for the Black Oak substation near the Maryland-West Virginia border prior to the summer of 2008. This SVC addresses post-contingency low voltages (reactive limit) for west to east transfers. The SVC is listed in the PJM RTEP report at http://www.pjm.com/planning/downloads/20070301-rtep-reinforcements.pdf.

RFC actively participates in the newly-formed Eastern Interconnection Reliability Assessment Group (ERAG) interregional transmission assessment efforts. ERAG coordinates all interregional studies throughout the Eastern Interconnection and replaced the former separate region-to-region interregional study forums. Transfer capability results are included in each of the three interregional study reports.

Since the August 14, 2003 blackout, the number of regional study scenarios has increased significantly. There are now about twice as many transfer scenarios and about three times as many voltage scenarios included in the RFC transmission assessment studies than were studied before the blackout.

Operations

The Midwest Independent System Operator (MISO) and PJM Interconnection are performing the reliability coordinator functions for all of the balancing authorities within the region.

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.

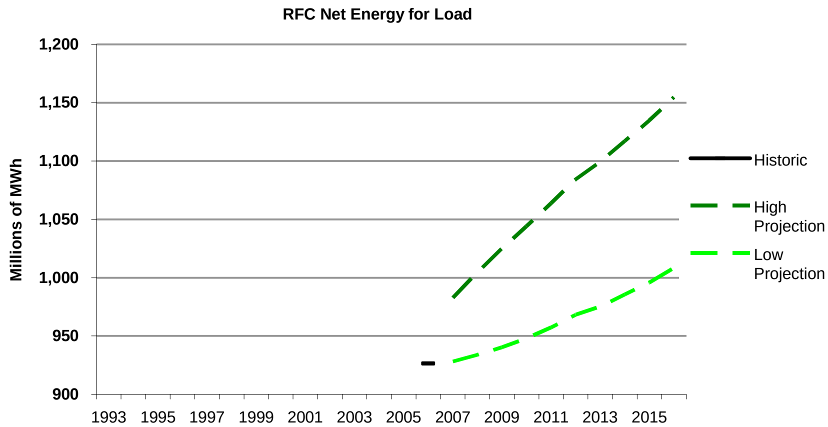
No operating issues have been identified in the assessment period for the PJM area of Reliability*First*. Neither does RFC foresee any potential operating issues during the assessment period for the Midwest ISO area within RFC.

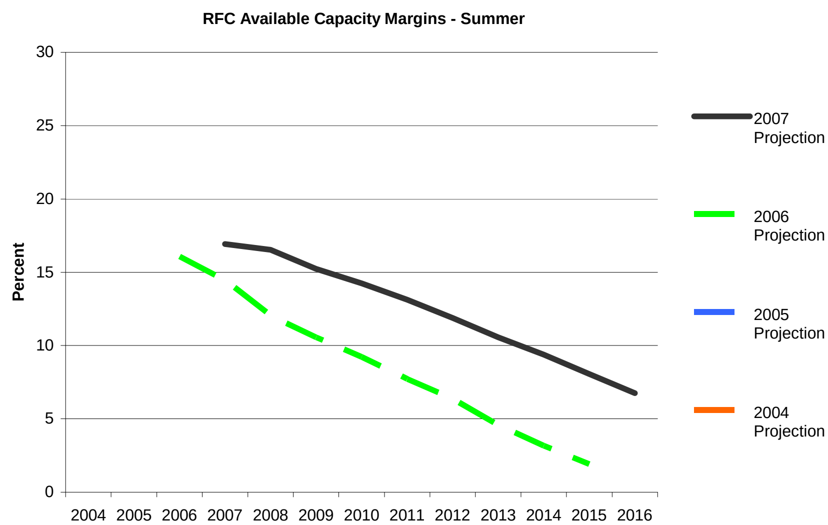
Governmental regulations on power plant emission levels continue to change over time, generally toward stricter emissions standards. Whether the changes modify standards to reduce existing emissions, or require previously uncontrolled emissions to be subject to control and reduction, changes will be necessary in power plant design and/or operation. Changes in design and operation brought about by changing regulations may result in reduced net unit capability or unit retirements. Any reduction or retirement of generating capacity will require additional new capacity resources beyond those identified in this report. As future emissions legislation raises reliability issues, Reliability*First* will conduct the necessary reliability analyses.

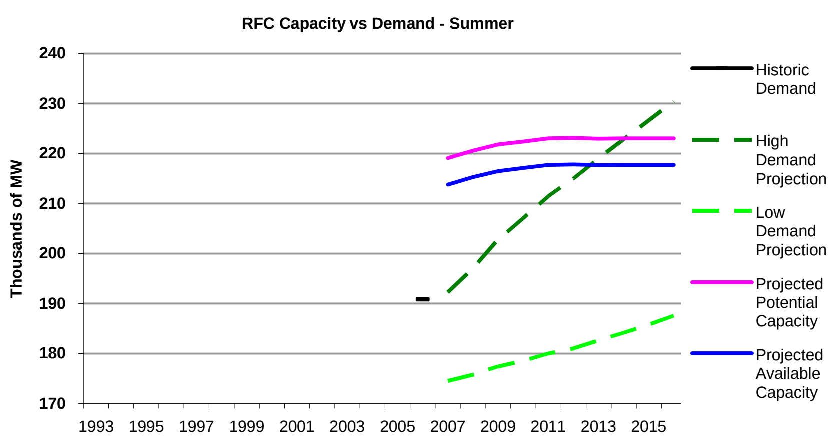
Region Description

*Reliability*First *currently consists of 43 Regular Members, 20 Associate Members, and 3 Adjunct Members operating within 12 NERC balancing authorities, which includes over 360 owners, users, and operators of the bulk power system. They 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 *website (http://www.rfirst.org).*

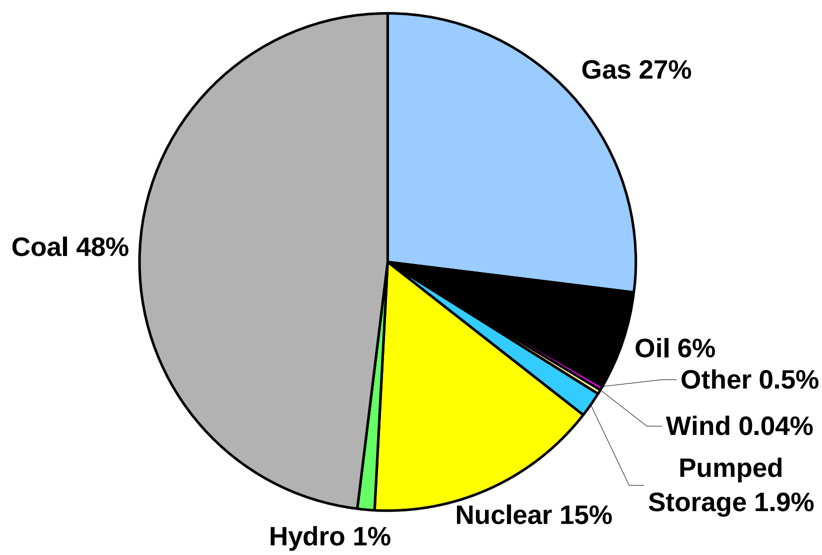
RFC Capacity and Demand



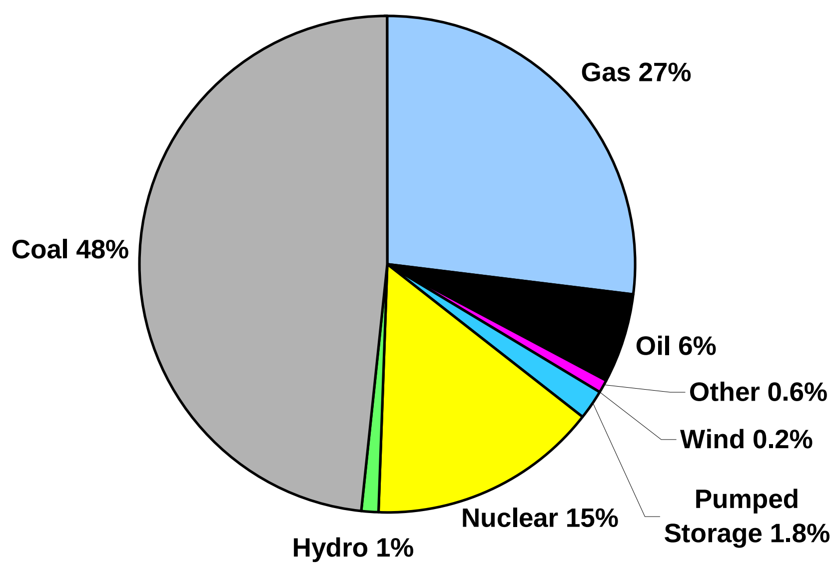




RFC Capacity Fuel Mix 2006



RFC Capacity Fuel Mix 2012



SERC

Introduction - SERC continues to experience significant transition:

- Effective January 1, 2007, SERC membership expanded to include several additional members in the central part of the country, including two new members within the Gateway subregion, Dynegy and City of Springfield, Illinois.
- Also effective January 1, 2007, three new SERC members joined the CENTRAL subregion: E.ON U.S. Services Inc. for LG&E & KU Companies; Owensboro, KY Municipal Utilities; and SUEZ Energy Marketing NA, Inc.
- Major changes in the electric utility industry were mandated by the Energy Policy Act of 2005. In April 2007, the Regional Delegation Agreements were approved by FERC. SERC continues to implement organizational and other changes, as appropriate, to align with the legislation.

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

Peak Demand and Energy

SERC anticipates consistent load growth in demand and energy over the next ten years. The 2007 summer total internal demand forecast is 202,103 MW and the forecast for 2016 is 239,406 MW. The compound annual growth rate over the next ten years is 1.9 percent. This is slightly lower than last year's forecast growth rate of 2.1 percent, which does not include members added since last year's data reporting. The historical growth rate has averaged 2.4 percent over the last 7 years, including the loads of membership additions to the region in the 2006 and 2007 total loads. Without the impact of new membership in 2006 and 2007, the growth rate for the region was 1.7 percent.

Due to the geographic size of the region, all reported demands are non-coincident. These forecasts are based on average historical weather peaking conditions. There were no significant changes in weather or economic assumptions since last year's forecast.

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 increase slightly over the forecast period from 5,672 MW in 2007 to 5,936 MW in 2016. These amounts are higher than last year's projections due, in part, to the addition of new members. Also, a change in reporting philosophy regarding demand response programs within certain companies resulted in the additional increase in interruptible demand and demand-side management. However, an offsetting adjustment was made to the demand reported, resulting in no net change due to the different reporting philosophy. In addition to the reported interruptible demand and load management, there are other demand-side management programs that 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 used can result in actual peak demands that vary considerably from the reported forecast peak demand. Although SERC does not perform extreme weather or load sensitivity analyses at the region level to account for this, SERC members address these issues in a number of ways, considering all NERC, SERC, regulatory, and other requirements. These member methodologies must be documented and are subject to audit by SERC.

While member methodologies vary to account for differences in system characteristics, the methodologies share many common considerations including:

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

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

Regarding the influence of weather, the 90th percentile peak temperature relates to an extreme weather peak of about 6 percent higher than the regular forecast for the region. An extreme peak for 2007 summer equates to 206,649 MW of firm peak demand for the region. Even at this extreme peak, SERC would have an 8.8 percent capacity margin, a reduced, yet adequate level for these conditions. Since capacity margins for SERC are fairly constant for the 10-year period, the results of this 2007 summer example can be extrapolated to conclude that extreme weather is not expected to reduce resource adequacy to critical levels.

Energy- The actual annual electric energy usage in the SERC region during 2006 was 1,011,173 GWh. The forecast annual electric energy usage in the SERC region during 2007 is 1,041,032 GWh. This is an increase of 3.0 percent. The forecast annual growth rate in energy usage for the region over the next ten years is 1.7 percent, the same as last year's forecast growth rate. The historical SERC growth rate for the last ten years has been 2.4 percent, including the loads of membership additions to the region in the 2006 and 2007 total loads. Without the impact of new membership, the historical growth rate for the region is 1.8 percent about the same as the forecast growth rate.

Resource Adequacy Assessment

Capacity resources in the region 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, non-firm or potential future resources to SERC members and others.

SERC believes that capacity resources will be sufficient to provide adequate and reliable service for forecast demands throughout the long-term assessment period. The 2007 forecasted capacity margins are projected to remain at or above 12.5 percent throughout the ten-year period. Capacity margins from last year's forecast remained at or above 14 percent throughout the ten-year period. This year's forecast is slightly lower than last year's due mainly to the effects of the 2006 Illinois Auction in the Gateway Subregion. Capacity margins reported for the Gateway subregion last year were above 30 percent considering the large portfolios of IPP generation connected in the Gateway subregion that were under contract to serve retail load. The change in the subregion capacity margin is primarily due to the 2006 Illinois Auction process for procuring generation resources in a market situation. The results of the Auction effectively lowered the reported capacity margins as some generators that were previously committed to serving Illinois retail load in 2006 were not selected during the auction process and are now indicated as uncommitted for 2007 and beyond. SERC believes this does not impact reliability because the unselected generators still exist and are available for power purchases.

Uncommitted generating 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 has reported the arrangement through the EIA-411 reporting process, then this capacity is included in this capacity margin assessment. Because significant uncommitted capacity exists in the region, there will continue to be additional generation above that reported in the capacity margin trend. Capacity margin calculations also assume the use of load management and interruptible contracts at the time of the annual peak.

Collectively, SERC members are projected to be net exporters of firm power across regional boundaries throughout the ten-year period. Firm purchases from SPP reach over 600 MW, but are offset by sales to SPP of about 150 MW. Firm sales to FRCC exceed 2,000 MW during the ten-year period. Firm purchases from RFC reach over 1,000 MW, with offsetting firm sales of 100 MW. Over 150 MW of the RFC purchases 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 or internal business practices as they plan for adequate generation 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 firm capacity is obtained, the system is planned and operated in accordance with NERC Reliability Standards to meet projected customer demands and provide contracted transmission services. Therefore, SERC anticipates no significant transmission constraints that would reduce the availability of committed capacity resources across the region. In addition, a significant amount of the uncommitted merchant capacity within the region has been participating in the short-term markets indicating that portions of uncommitted generation are deliverable during certain system conditions.

Resources are expected to be adequate even if resource unavailability is higher than expected since SERC entities recognize that planning for variability in resource availability is necessary. Many SERC members manage this variability through reserve margins, demand side management programs, fuel inventories, diversified fuel mix and sources, and transfer capabilities. Some SERC members participate in Reserve Sharing Groups (RSG). In addition, emergency energy contracts are used within the region and with neighboring systems to enhance recoverability from unplanned outages.

The projected 2007 capacity mix reported for SERC is approximately 39 percent coal, 15 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. 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.

The majority of planned capacity additions is comprised of gas/oil fueled combustion turbine or combined cycle units. However, there are recent additions and plans in the ten-year planning horizon for coal-fired and nuclear plant additions. Note that the long term unit projections are subject to change through the planning horizon. Some examples are:

Recent Additions:

- Central Subregion: Browns Ferry (nuclear) unit 1 –1,280 MW Operational May 2007
- VACAR Subregion: Cross (coal) unit 3 – 650 MW operational January 2007

Projected Additions:

- Delta Subregion: 1,520 of nuclear addition in 2015
- Gateway Subregion: 1,650 MW merchant coal plant in 2011
- Southeastern Subregion: 1,200 MW merchant coal plant in 2010 (date of interconnection requested by merchant plant); 600 MW nuclear addition in 2016 (represents a reported 600 MW of allocated ownership from a likely 1,200 MW unit)
- VACAR Subregion: 650 MW coal additions in 2009; 1,600 MW nuclear plant for interconnection in 2015

Transmission planning activities are underway to study the impact of planned additional nuclear generation on system reliability. System impact studies are being performed as interconnection requests are received. Some proposed nuclear additions have been analyzed in joint studies such as the Georgia/Carolinas Coordinated Nuclear Expansion Joint Study. Other joint study efforts have been initiated as well. As transmission improvements necessary to support nuclear additions are identified and are projected for the 10-year planning period, they will be captured in future LTRA data submittals and the annual SERC Transmission Development Survey.

Of the approximately 45,000 MW of planned resource additions reported for the 2007-2016 time period, 15 percent are combined cycle, 19 percent are combustion turbine, 27 percent are steam (including nuclear), 10 percent are net purchases and 29 percent are categorized as "Other/Unknown". The "Other/Unknown" category includes projected additions that do not have finalized implementation plans. The most notable change from last year is the net increase in the steam category from 11 percent to 27 percent. It appears that entities are continuing to increase plans for future coal or nuclear base load generation instead of relying on natural gas-fired generation or purchases.

Generation Development in SERC

There has been significant merchant generation development in SERC since 1998, especially in the Southeastern and Delta subregions. Most of this merchant generation was intended for commerce 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 the Table 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."

Current Status of Generation Plant Development

Current Status of Generation Plant Development	In-Service Year of Added Generation (MW)										
Category	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Total**
1. **Interconnection Service Requested, Only**	622	91	3459	3158	3779	2567	1281	1938	8263	2700	**27858**
• Designated as Network Resource or has obtained Firm PTP Transmission service	419	0	1310	967	1405	1934	1281	1928	6663	1160	**17067**
• Uncommitted	203	91	2149	2191	2374	633	0	10	1600	1540	**10087**
2. **Interconnection Agreement Signed/ Filed**	2565	2155	2309	4511	1955	916	76	1274	85	335	**16181**
• Designated as Network Resource or has obtained Firm PTP Transmission service	2024	963	2153	1526	380	91	76	1274	85	335	**8907**
• Uncommitted	541	1192	156	2985	1575	825	0	0	0	0	**6670**
3. **Unit Retirements**	148	0	0	272	298	198	0	0	0	0	**916**

Net Projected Additions

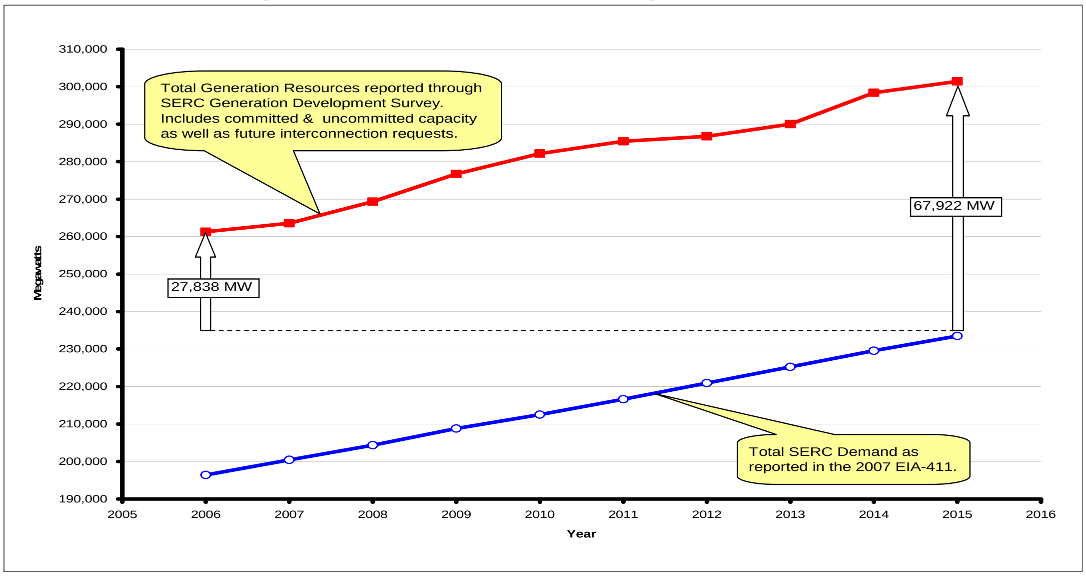
*Source — SERC Reliability Review Subcommittee 2007 report to the SERC Engineering Committee

The survey indicates that an additional 3,187 MW of generation plant capacity is expected in the SERC region for the 2007 summer, with 148 MW of retirements scheduled, resulting in net projected additions of 3,039 MW. In the near-term planning horizon there is significant speculation about the amount of generation that will be added (approximately 24,600 MW of which over 11,000 MW fall in category 1), but the amount to actually be constructed will likely change before the next annual survey. The trend from last year's survey to this year's indicates that more generation resources are finalizing plans for construction, since in the near-term category 2 additions now outnumber those in category 1.

Category 2 additions are significantly smaller in the longer-term. However, the more speculative category 1 additions remain high throughout the 10-year period. This pattern is not unexpected since plans for the longer-term continue to undergo review and revisions. The 28,100 MW of generation development reported in the first six years of this year's survey is significantly higher than the 24,100 reported in last year's survey. Approximately half of the increase is due to generation additions by the new membership in the region. The additional increase is primarily due to new proposals for large base load generators. 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.

SERC's 2007 Generation Development Survey indicated that, as of December 31, 2006, the total generation connected to the transmission systems within SERC exceeded 258,000 MW. Including the additions and retirements planned for this spring, the total generation resources connected within SERC are expected to exceed 261,000 MW by July 1, 2007. These values differ slightly from the EIA-411 data reported in Table 2 due to inoperable capacity and mothballed units. The total generation connected to the SERC systems in the year 2007 exceeds projections for SERC regional load in the year 2016 by over 27,000 MW. If the proposed capacity described in Table 4 (above) is completed, installed generation could exceed forecast peak demand by almost 68,000 MW in 2016 (see Figure below). This is significantly more than the generation capability needed for reliability/adequacy in the region.

Proposed Generation Development in SERC



*Source — SERC Reliability Review Subcommittee 2007 Generation Development Survey

Fuel Supply & Delivery

Fuel supplies are expected to be adequate to meet forecast demands over the next 10 years. 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 to reduce reliability risks due to fuel supply issues. SERC entities with large amounts of gas-fired generation connected to their systems have conducted electric-gas interdependency studies. In-depth studies have simulated pipeline outages for near- and long-term study periods as well as both summer and winter forecasted peak conditions. Also included, for each of the major pipelines serving the service territory, is an analysis of the expected sequence of events for the pipeline contingency, replacing the lost generation capacity, and assessment of electrical transmission system adequacy under the resulting conditions. Other SERC entities with less impact from gas generation are completing activities to map generators to their respective pipelines from which they are served. Dual fuel units are tested to ensure their availability and that back-up fuel supplies are adequately maintained and positioned for immediate availability. Some generating units have made provisions to switch between two separate natural gas pipeline systems, reducing the dependence on any single interstate pipeline system. Moreover, the diversity of generating resources serving load in the region further reduces the region's risk.

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

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 members are 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 other natural gas producing countries
- Monitoring the next wave of new generation additions over the next 10 - 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 Assessment

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 firm and non-firm 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. SERC members invested over $1.2 billion in new transmission lines and system upgrades in 2006, and are planning transmission capital expenditures of more than $8.9 billion over the next five years. Planned transmission additions over the next ten years include 1,494 miles of 230-kV lines, 261 miles of 345-kV lines, and 467 miles of 500-kV lines.
The existing bulk transmission system within SERC totals 50,020 miles of transmission lines comprised of 17,696 miles of 161-kV, 20,537 miles of 230-kV, 3,225 miles of 345-kV, and 8,562 miles of 500-kV transmission lines. SERC member systems continue to plan for a reliable bulk transmission system and plan to add 464 miles of 161-kV, 1,494 miles of 230-kV, 261 miles of 345-kV, and 467 miles of 500-kV transmission lines in the 2007–2016 time period. As reported in the 2006-2015 NERC LTRA Report, the bulk transmission expansion plans of SERC

region members is second only to the WECC. Furthermore, the planned transmission expansion in SERC represents approximately 20 percent of all transmission expansion in the U.S. over the next ten years. This marks the sixth consecutive year in which SERC has reported at least one-fifth of all planned U.S. transmission expansion. SERC members invested over $1.2 billion in new transmission lines and system upgrades in 2006, and are planning transmission capital expenditures in excess of $8.9 billion over the next five years.

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 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 and applicable contingency system conditions as prescribed in the NERC Reliability Standards (see Table 1, Category B of NERC Reliability Standard TPL-002-1) and the member companies' planning criteria relating to transmission system performance.

Operational Issues

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 intra-regional transmission reliability and transfer capability studies for the longer term planning horizon were conducted within SERC. These studies indicate that the bulk transmission systems within SERC and between adjoining regions can be expected to provide adequate and reliable service over a range of system operating conditions.

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

Subregions

SERC serves as a regional entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the SERC Region. SERC is divided geographically into five subregions that are identified as Central (formerly TVA), Delta (formerly Entergy), Gateway, Southeastern (formerly Southern), and VACAR. SERC and its five subregions are all summer peaking.

Delta

Peak Demand and Energy — The 2007 summer net internal demand forecast for the Delta subregion was 27,114 MW and the forecast for 2015 is 32,151 MW. The compound annual growth rate over the next 10 years is 1.9 percent, which is comparable to last year's forecast growth rate. The historical growth rate has averaged 1.6 percent. The increase in annual growth rate over the historical growth rate is due in part to load recovery within the New Orleans metropolitan area.

The 2007 annual electric energy usage forecast for the Delta subregion is 145,850 GWh and the forecast for 2016 is 171,468 GWh. The forecast growth rate in energy usage is 1.8 percent. The historical growth rate was 1.4 percent pre-Katrina and 1.0 percent post-Katrina. The forecast growth rate is higher than the historical due to the continued repopulation of certain areas in the subregion.

Resource Adequacy Assessment — Projected capacity margin was 15.2 percent for the 2007 summer, dips to about 10 percent for a year and then rebounds to around 14-15 percent for the remainder of the ten-year period. There are large amounts of uncommitted generation in the subregion that could provide additional capacity when necessary. The one year dip in capacity margin is a result of resources that subregion members are currently evaluating and thus were not reported. The rebound is due to planned network resources for those outward years.

Transmission Assessment — Planned transmission additions include 160 miles of 161 kV lines, 292 miles of 230-kV lines, 105 miles of 345-kV lines, and 18 miles of 500-kV lines. Most of these planned transmission additions are to address load growth and contingency loadings and voltages. Some projects will also enhance power transfer capabilities into certain load pockets such as the Amite South area in southeast Louisiana.

A new 161 kV station will be built in northwest Arkansas to interconnect Entergy's and Southwest Power Administration's (SWPA) facilities in the area. This connection will eliminate thermal overloads and low voltages which could potentially occur under contingency conditions. This project is expected to be in service by fall 2007.

A second circuit from Entergy's Sterlington 500 kV station to the Perryville 500 kV station, both in north Louisiana, was placed in service in March 2007. A second 500/230 kV autotransformer at Entergy's Ray Braswell station in Mississippi is in-service. These transmission system additions will complete an upgrade package to enable long-term service from the Perryville power plant as a network resource.

Operational Issues — Entergy continues to monitor load shifts in the areas affected by Hurricanes Katrina and Rita. While the entire subregion expects to experience load growth in 2007, the growth rate in the New Orleans area is expected to be higher than in other areas as resettlement of the city continues post-Katrina. The areas just north of New Orleans as well as areas around Houston, TX and Jackson, MS are expected to experience continuing higher than average load growth within the subregion. Most loads affected primarily by Rita (i.e., outside of southeast Louisiana) have returned to pre-storm levels. No near-term 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, based on load distribution and system reliability needs in the area affected by Hurricane Katrina, two transmission substations and one transmission line in southeast Louisiana will not be returned to service. 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 have, for the most part, recovered in the aftermath of Hurricanes Katrina and Rita. Most major production, processing, and transportation facilities have returned to service, but may currently operate at less-than-normal capability in the near-term due to limited production facilities in the Gulf of Mexico. These industries in the Entergy service territory will, in fact, experience a high growth period in the near future, as evidenced by several planned facility construction and expansion projects.

Regarding hurricane impact on Entergy's transmission construction and design practices, Entergy Company is currently performing a hardening study to establish whether or not specific hardening strategies are economically justified. Entergy already meets and exceeds the National Electrical Safety Code requirements for extreme wind.

Gateway

Peak Demand and Energy — The 2007 summer net internal demand forecast for the Gateway subregion was 18,821 MW and the forecast for 2016 is 20,611 MW. The compound annual growth rate over the next ten years is 1.0 percent. Since 2000, the annual growth rate has averaged 1.9 percent including the effects of adding new members to the subregion. The historical growth rate without the influence of adding new members has been 1.2 percent.

The 2007 annual electric energy usage forecast for the Gateway subregion was 93,408 GWh and the forecast for 2016 is 104,897 GWh. The forecast growth rate in energy usage is 1.3 percent. The historical growth rate over the last ten years has averaged 1.3 percent. However, this includes the effects of adding new members to the subregion. The historical growth rate without the influence of adding new members has averaged 0.9 percent.

Resource Adequacy Assessment — Projected capacity margin for the Gateway subregion was 21.3 percent for the 2007 summer, and is expected to decline gradually to approximately 10 percent over the remainder of the planning period assuming continuation of the existing Illinois Auction process that has no long-term capacity purchase requirements. However, at the time of this writing the process for procuring capacity resources to meet the demand and reserve requirements in Illinois is under review by the Illinois legislature and will likely change. Historically, the major utilities in the subregion have maintained a planning reserve margin of approximately 15 percent, and maintaining planning reserves at these levels should not be a problem considering the large amount of existing uncommitted capacity in the subregion and in neighboring regional entities. In addition to the 1650 MW Prairie State coal-fired merchant plant development in 2011, generation developers representing over 1000 MW of coal-fired generation and 4000 MW of wind generation have requested interconnection service in the subregion within the next five years. Most of these proposed developments are in Illinois, and are in various stages of study and negotiation.

Transmission Assessment — Planned transmission additions include 57 miles of 345-kV lines, most of which are required for the connection and deliverability of the Prairie State (1650 MW) coal-fired plant in southwest Illinois.

The addition of the Callaway – Franks 345 kV line from Ameren to AECI was completed and placed in service in December 2006. This line provides loading relief to the Bland – Franks 345 kV line, improves reliability in central Missouri, and will serve as a supply to a new station in the Jefferson City area in 2008. These new facilities would also unload local area facilities and help to increase transfer capability from SERC (Gateway) to SPP. These upgrades and others result in greater system flexibility and increased reliability for the subregion and its neighbors.

Operational Issues — No major changes in operations are expected for 2007 summer conditions. The Midwest ISO energy market has matured since its start on April 1, 2005, and joint agreements with TVA, PJM, and SPP should further help the Midwest ISO to limit escalation of flows and to reduce the need for TLR with this increased coordination.

In the longer-term, there are operational concerns, primarily during off-peak conditions, as wind and other intermittent generation resources are developed in the Gateway subregion and surrounding regional entities. Possible concerns regarding these intermittent resources are increased loop-flows and redispatch of large base load coal-fired and nuclear generating plants while managing transmission facility loadings. These concerns are expected to lessen during summer peak conditions when the availability of the local area wind resources in the subregion would be significantly reduced.

Southeastern

Peak Demand and Energy — The 2007 summer net internal demand forecast for the Southeastern subregion was 48,279 MW and the forecast for 2016 is 59,899 MW. The compound annual growth rate over the next ten years is 2.4 percent. This is the same as last year's forecast growth rate. The historical growth rate has averaged 2.7 percent.

The 2007 annual electric energy usage forecast for the Southeastern subregion was 249,237 GWh and the forecast for 2016 is 304,507 GWh. The forecast growth rate in energy usage is 2.3 percent. The historical growth rate for the last ten years is 2.5 percent.

Resource Adequacy Assessment — Projected capacity margin was forecast to be 14.3 percent for the 2007 summer, and remains at or above 13 percent over the entire planning period.

Transmission Assessment — Planned transmission additions include 22 miles of 161-kV lines, 628 miles of 230-kV lines and 232 miles of 500-kV lines.

The Southeastern subregion continues to exhibit active transmission expansion. Compared to data from the 2006-2015 NERC Reliability Assessment Subcommittee Report, the Subregion's plans for bulk expansion include more miles than all but three NERC Regions (including SERC), with a bulk transmission growth rate higher than all Regions except MRO. Numerous 230 kV and 500 kV additions are scheduled for the Southeastern subregion to serve load and address contingency loadings and voltages. A new interconnection between SMEPA and TVA is planned for operation on July 1, 2007 that will increase reliability in both the Southeastern and Central subregions. An existing SMEPA – Entergy interconnection will be upgraded, doubling its capacity, for summer 2007 operation.

Operational Issues —Management of the Northwest Quadrant stability limit is accomplished in real-time operations by monitoring a stability proxy that consists of a summation of flows on critical west to east lines within the Southern Balancing Area. Historically, the Northwest Quadrant stability limits have rarely been approached. The few times that the system has come close to the Northwest Quadrant stability limits, have been during off-peak load levels with elements out of service. The Northwest Quadrant may become more of an operating issue in the future if a significant amount of additional generation is added in this Northwest Quadrant. The second area, the Southwest Quadrant, is 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 online stability tools which system operations can use in managing the Northwest and Southwest Quadrants. The operating tools and procedures currently in place are considered adequate to reliably manage these two stability challenged areas.

The dynamic reactive needs of Atlanta and the North Georgia area have been met by siting a significant amount of new generation in the Atlanta area for the years 2010 and 2011. In addition, 260 MVARs of static VAR compensation (SVC) are also being sited in the North Georgia area by 2008 to meet the growing dynamic VAR needs of this region.

Central

Peak Demand and Energy — The 2007 summer net internal demand forecast for the Central subregion was 41,222 MW and the forecast for 2016 is 49,508 MW. The compound annual growth rate over the next ten years is 2.1 percent. This is slightly lower than last year's forecast growth rate of 2.2 percent. The historical growth rate is 5.2 percent. However, this includes the effects of adding new members to the subregion in 2006 and 2007. The historical growth rate without the influence of adding new members has averaged 2.1 percent.

The 2007 annual electric energy usage forecast for the Central subregion was 232,367 GWh and the forecast for 2016 is 262,015 GWh. The forecast growth rate in energy usage is 1.3 percent. The historical growth rate for the last ten years is 5.0 percent. However, this includes the effects of adding new members to the subregion in 2006 and 2007. The historical growth rate without the influence of adding new members has averaged 2.0 percent.

Resource Adequacy Assessment — Projected capacity margin was 13.4 percent for the 2007 summer, and ranges from 11.8 percent to 13.2 percent over the remainder of the planning period. In addition to the restart of Browns Ferry Nuclear Unit 1 (1280 MW) TVA has recently purchased previous IPP CT plants, Marshall (640 MW) and Gleason (510 MW). Additional resource expansion is expected to be confirmed in the near future.

Wolf Creek — Members of the Central subregion are monitoring the situation at Wolf Creek dam, a composite earth and concrete structure located at the head of the Cumberland River in south-central Kentucky and which contains the largest reservoir east of the Mississippi. In December 2006 the Army Corps of Engineers lowered the lake to approximately 40 feet below normal summer elevation to allow dam repairs. The repairs will continue for up to 7 years. Reductions resulting from the Wolf Creek dam repairs are not expected to affect peak capacity or system reliability.

Potential concerns for electricity supply are reduction in hydro generation and reduction in cooling water for downstream thermal plants, in particular Gallatin (988 MW) and Cumberland (2530 MW). Lowered levels at Lake Cumberland represent a decrease in stored water, making flows in the river system variable and the hydro system capacity (960MW) questionable during peak hours. Impacts on the fossil plants are expected to be minor. While de-rates are probable during the hot and dry conditions likely in July/August, it is expected that plant dispatch can be manipulated such that all de-rates can be taken off-peak. No effect on TVA's bulk system reliability is anticipated, but East Kentucky Power Cooperative's (EKPC) ability to supply its consumers may be constrained. The Southeastern Power Administration (SEPA) has implemented an Interim Power Marketing Policy in the Cumberland System based on power available from stream-flow.

Further degradation in the condition of Wolf Creek Dam resulting in the further lowering of Lake Cumberland is considered highly unlikely, but this has been studied together with 30 percent and 10 percent drought conditions and contingency plans developed. Operating Guides will be used as required. No effect on bulk system reliability within the Central subregion is anticipated.

***Transmission Assessment* —** Planned transmission additions include 262 miles of 161-kV lines, 99 miles of 345-kV lines, and 67 miles of 500-kV lines.

During periods of significant north-south transfers certain facilities in the subregion experience high loading. Transmission system upgrades of five 161 kV lines will be completed by the 2007 summer that will greatly reduce the loading on the limiting facilities.

EKPC is on schedule to have two new transmission facilities constructed and in-place by 2007 summer that will eliminate constraints in eastern and central Kentucky. A new 138kV line from Cranston to Rowan County will reduce loading issues on the E.ON Goddard - Rodburn 138kV line in eastern Kentucky. A new 345kV line from JK Smith to North Clark (located in the Spurlock - Avon 345kV Line) will provide an additional path for power to flow through central Kentucky, thereby reducing the flows through EKPC's Avon 345-138kV substation, and also, possibly reducing the need to run combustion turbines at JK Smith.

Big Rivers Electric Corporation (BREC) and E.ON have a new 345 kV interconnection planned for 2009 and will increase export capability from BREC.

***Operational Issues* —** As reported for previous years, the TVA transmission 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 are used to address these constraints.

Continuing growth in transmission grid loading and its limitation on outage availability for maintenance can impact exposure to stability events. During 2006, TVA observed unexpected behavior in a large coal generating plant following the scheduled switching of a 500 kV line.

Subsequently power system stabilizers were installed and stability criteria reviewed to ensure adequate conservativeness in generating plant and grid models.

VACAR

Peak Demand and Energy — The 2007 summer net internal demand forecast for the VACAR subregion was 60,603 MW and the forecast for 2016 is 70,958 MW. The compound annual growth rate over the next ten years is 1.8 percent. This is slightly lower than last year's forecast growth rate of 2.0 percent. The historical growth rate has averaged 2.1 percent.

The 2007 annual electric energy usage forecast for the VACAR subregion was 320,171 GWh and the forecast for 2016 is 369,069 GWh. The forecast growth rate in energy usage is 1.6 percent. The historical growth rate for the last ten years is 1.8 percent.

Resource Adequacy — Projected capacity margin was 13.1 percent for the 2007 summer, and ranges from 11.7 percent to 13.0 percent over the remainder of the planning period.

Transmission Assessment — Planned transmission additions include 20 miles of 161-kV lines, 574 miles of 230-kV lines and 150 miles of 500-kV lines.

Several improvements to VACAR facilities have been completed or are planned. Two additional 230 kV interconnections between Progress Energy-Carolinas and South Carolina are scheduled to be placed in service prior to the 2007 Summer Peak. Also, a Static VAR Compensator (SVC) will be added in the northern North Carolina area of the subregion by June 2007 to reinforce voltages for certain load levels and unit outage combinations. The SVC will be connected at 100 kV and operate over a dynamic range of 100 MVAR reactive to 300 MVAR capacitive. Re-dispatch and load reductions can also be used to manage voltages in this area, if necessary.

A project to increase the capacity of the VACAR-TVA interface is expected to be completed by July 2009 and should eliminate the need for the operating guides to manage loading on that interface. Planned additions also include a new 500 kV RFC-SERC interconnection, planned for 2011. The combined 502 Junction to Mt. Storm, Mt. Storm to Meadow Brook, and Meadow Brook to Loudoun 500 kV circuits will reduce loadings on limiting facilities and improve voltage problems.

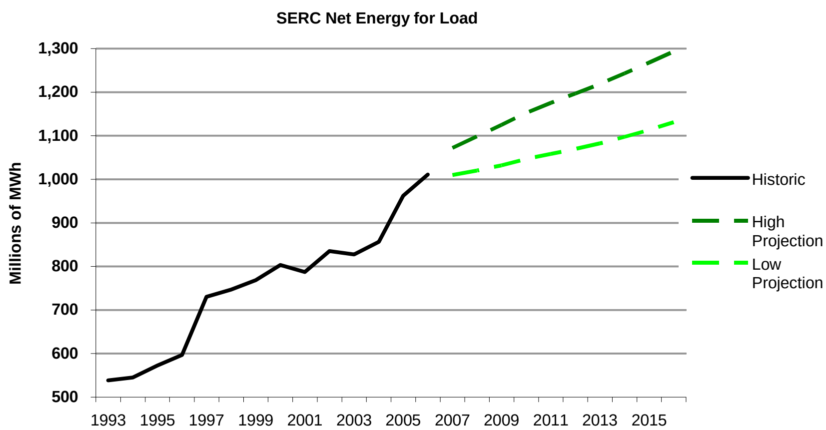
Operational Issues — As reported in previous assessments, heavy loading internal to the VACAR subregion could be experienced on several facilities. Studies have shown that generation internal to VACAR can be redispatched to relieve the loading on these internal lines, if necessary.

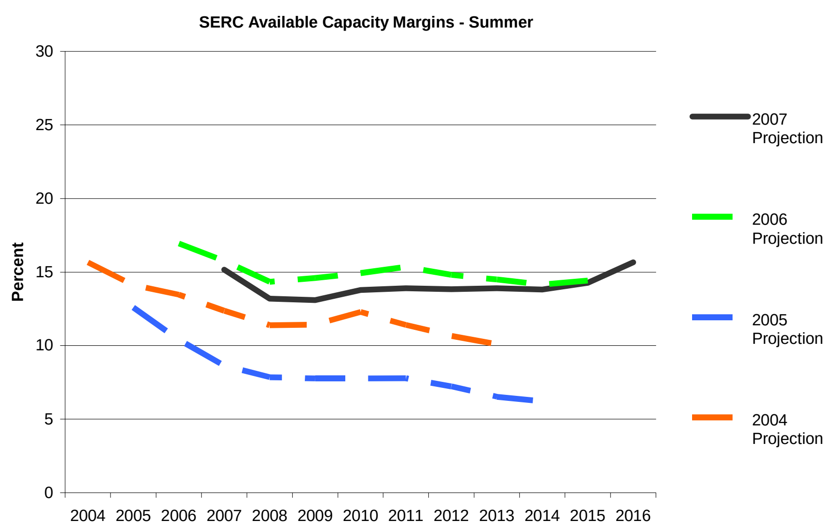
Region Description

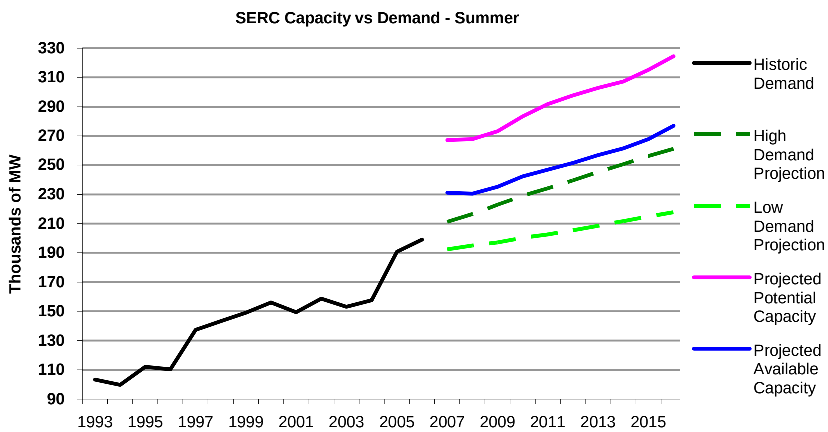
The SERC Reliability Corporation (SERC) is a nonprofit corporation responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply systems in all or portions of 16 central and southeastern states (all of Alabama, Georgia, Mississippi, North Carolina and South Carolina, and portions of Arkansas, Florida, Illinois, Iowa, Kentucky, Louisiana, Missouri, Oklahoma, Tennessee, Texas and Virginia). SERC's 63 *members comprised of investor-owned utilities, municipal, cooperative, state and federal systems, RTOs/ISOs, merchant electricity generators, and power marketers, cover an area of approximately 560,000 square miles and serve approximately 40 million customers.*

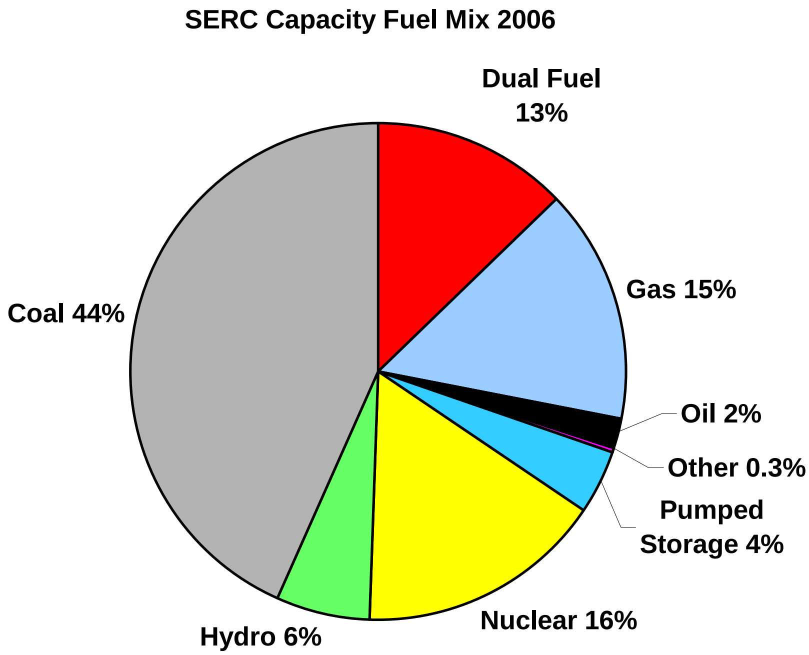
SERC serves as a regional entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the SERC Region. SERC is divided geographically into five subregions that are identified as Central, Delta, Gateway, Southeastern, and VACAR. SERC and its five subregions are all summer peaking. Additional information can be found on the SERC Web site (www.serc1.org).

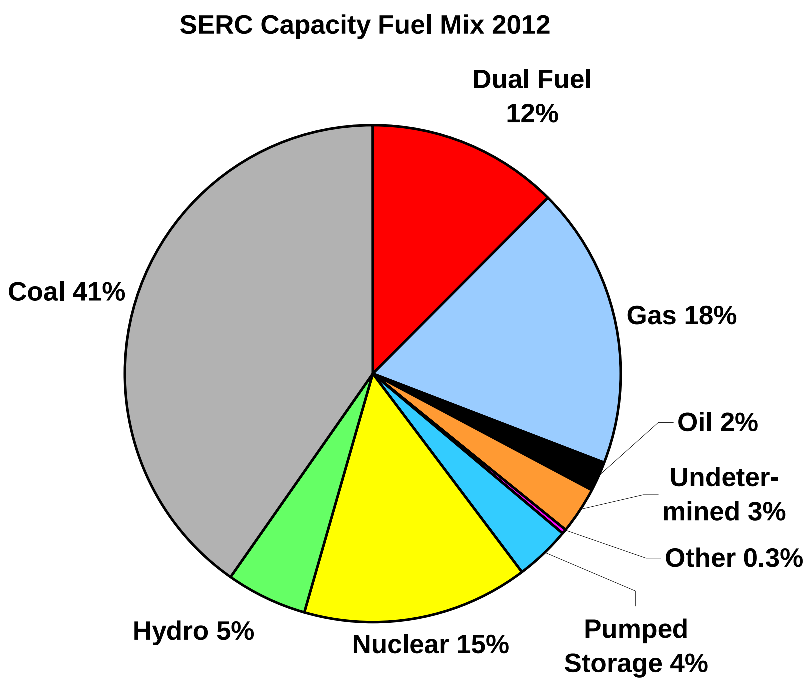
SERC Capacity and Demand






SERC Capacity vs Demand - Summer
Thousands of MW
330
310
290
270
250
230
210
190
170
150
130
110
90
1993 1995 1997 1999 2001 2003 2005 2007 2009 2011 2013 2015
Historic Demand
High Demand Projection
Low Demand Projection
Projected Potential Capacity
Projected Available Capacity


SERC Capacity Fuel Mix 2006
Dual Fuel 13%
Gas 15%
Oil 2%
Other 0.3%
Pumped Storage 4%
Nuclear 16%
Hydro 6%
Coal 44%


SERC Capacity Fuel Mix 2012
Dual Fuel 12%
Gas 18%
Oil 2%
Undeter- mined 3%
Other 0.3%
Pumped Storage 4%
Nuclear 15%
Hydro 5%
Coal 41%

SPP

Introduction - Southwest Power Pool (SPP) anticipates consistent growth in demand and energy consumption over the next ten years. Significant generation capacity of uncommitted resources is forecasted in SPP to be available throughout the planning horizon to meet native network load needs with committed generation resources meeting minimum capacity margins until 2015.

The successful launch of SPP's Energy Imbalance System (EIS) Market Operations this year and growing popularity of demand–side load management programs are helping the existing transmission system become more efficient. Although, the existing bulk transmission system is expected to reliably serve the needs of native network load for the short term, incremental system flows from commercial transmission reservations will most likely use any remaining transmission capacity. As always a top priority is the SPP Transmission Expansion Planning (STEP) process which further addresses the reliability and economic needs of the region for the ten year planning horizon.

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

Peak Demand and Energy

According to the most recent data, the projected annual rate of growth for peak demand in the SPP region over the next ten years is 1.7 percent, from 43,007 MW in 2007 to 50,608 MW in 2016. This compares to the 2006 LTRA ten–year (2006–2015) forecasted growth rate of 1.3 percent.

For the 2007–2016 timeframe, the projected annual rate of growth for energy consumption in the SPP region is 1.8 percent, from 205,163 GWh in 2007 to 243,817 GWh in 2016. This also compares to the previously forecasted growth rate of 1.3 percent.

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

- Each member selects its own demand forecasting method and establishes its own forecast.
- Each member forecasts demand based on expected weather conditions. In the case of extreme weather, peak demand would be increased by 2.9 percent.
- 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 sub–regional demand and energy forecasts. To ensure against negative impacts due to forecast error, SPP requires a 12 percent capacity margin.

Although actual demand is very dependent upon weather conditions and typically includes interruptible loads, forecasted net internal demands used for assessing net capacity margins are based on normal weather conditions and do not include interruptible loads.

Resource Adequacy Assessment

For the 2007–2016 assessment period, the net capacity margin reflected by current EIA–411 data show that SPP maintains an average annual capacity margin of 13.1 percent, ranging from 14.7 percent in 2007 down to 11.0 percent in 2016. This forecasted average net capacity margin, which is only based on committed resources, is 0.5 percent greater than previous forecasts. On the whole, the annual net capacity margin for SPP is greater than the required 12 percent until the year 2015, where the margin drops to 11.3 percent. While the EIA–411 data does not include the 9,758 MW of uncommitted resources that are located within the SPP footprint, it is important to note that some of these resources may not be available on a firm basis.

Over the next ten years, SPP anticipates installation of around 10,000 MW in nameplate capacity, 70 percent of which is expected to be fossil fueled. The remaining 30 percent is anticipated to be wind–driven generation that can only be expected to contribute between zero and 20 percent of nameplate rating during summer peak loading.

SPP criteria require that members maintain a 12 percent capacity margin, unless their system is primarily hydro–based where the required margin is lowered to 9 percent. Because wind and hydro capacity only make up about 7.5 percent of SPP capacity, these minimum capacity margin requirements are sufficient to cover a 90/10 weather scenario.

Although the results of our 2007 Supply Adequacy Audit have not yet been released, we are working on qualifying our member’s processes for estimating existing and future generation capacity.

SPP’s Transaction Database, which may consist of firm and non–firm data, is used to track long–term regional sales and purchases. Annually averaging 1,480 MW, regional sales are apportioned into 49 MW to ERCOT, 365 MW to WECC, 967 MW to SERC, and 99 MW to RFC. These sales projections compare to previous ten–year estimates.

Additionally, a small portion of the capacity margin depends on the purchases from other regions. Annually, transactions totaling 1,751 MW are purchased from other regions. 1,646 MW of these transactions are 218 MW from ERCOT, 1,134 MW from SERC, 250 MW from RFC, and 44 MW from MRO. The remaining 105 MW are firm delivery service from WECC which are administered under Xcel Energy’s OATT. Although the previous ten–year projection estimated 0 MW from WECC and 250 MW from MRO, the total of annual purchases was comparable to this year’s projections.

These capacity margin projections include the effects of demand–side response programs, such as direct–control load management and interruptible demand. Available demand relief from direct–control load management programs are expected to rise from 15 MW in the summer of 2007, up to 54 MW in 2016. Additionally over the next ten years, interruptible demand relief is also expected to increase from 746 MW to 787 MW. SPP views demand–side management programs as extremely beneficial to both members and consumers and, according to SPP's Strategic Plan, has determined that increasing availability of them to consumers is one of the top priorities going forward.

Energy only, uncommitted resources and transmission–limited resources are not used in calculating net capacity margin. As previously stated, the EIA–411 data does not include the 9,758 MW of uncommitted resources that are located within the SPP footprint. These are reflected in the total potential resources capacity margin which is considerably greater than the net capacity margin.

As previously stated, SPP expects around 10,000 MW of new committed generation, three–quarters of which is expected to be fossil–fueled. Additionally, the majority of new uncommitted generation interconnect requests are wind–based reflecting an increased interest in the development of the available and abundant wind resources located within the SPP footprint. To date, there have been no requests for new nuclear–fueled generation in SPP.

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

There are no known environmental or regulatory restrictions that are expected to impede reliability during peak loading periods.

Fuel Supply and Delivery

SPP monitors potential fuel supply limitations by consulting with its generation owning and controlling members at the beginning of each year. Presently, there are no known infrastructure issues which could affect deliverability as SPP is blanketed by major pipelines and railroads to provide an adequate fuel supply. In addition, coal–fired power plants are required by SPP criteria to keep sufficient quantities of standby fuel in the case of deliverability issues. As previously stated, because hydro capacity is a small fraction of capacity for the region, run–of–river hydro issues brought about by extreme weather are also not expected to be critical.

Transmission Assessment

For the purposes of maintaining reliability, several new transmission projects and those intended to upgrade existing transmission have already been or are close to completion by SPP Members.

- American Electric Power West (AEPW) completed in the fall of 2006, a new 20 mile section of 138 kV transmission line between Pittsburg and Winnsboro in northeast Texas.
- AEPW also has just completed reconductoring the Chamber Springs–Tontitown 161 kV transmission line, and has completed 8 miles of new 161 kV line between Siloam Springs and Chamber Springs energized by this summer both of which will improve reliability in

northwest Arkansas.

- AEPW is also reconductoring the 2 mile 138 kV transmission line between the Northwest Texarkana and Alumax Tap substations to help improve reliability in the Texarkana, Texas area.
- Empire District Electric (EMDE) is constructing 4.2 miles of new 161 kV transmission line between the Reinmiller and Tipton Ford substations to improve the reliability in southwest Missouri.
- Westar Energy (WERE) will be constructing a new 7 mile 115 kV transmission line between the Stranger Creek and Thornton Street substations to enhance reliability northwest of Kansas City, Kansas.
- Westar Energy (WERE) has rebuilt the 115 kV transmission line between Hutchinson and Circle and rebuilt 69 kV transmission line between Hesston and the Golden Plain Tap to improve reliability in the Hutchinson, Kansas area.

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

The transmission system within SPP is expected to perform reliably over the 2007 summer load season. Specific concerns such as the line loadings on the 115–161 kV transmission lines along the Oklahoma and Arkansas border are being evaluated more closely.

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

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

There are no known issues or concerns that could impact the reliable operation of the transmission system at present. This is because there are no scheduled maintenance outages of operational concern. SPP does not anticipate any environmental and/or regulatory restrictions that could potentially impact reliability. There will be no impact from a large nuclear start–up in our region as none is expected as of yet and wind resources should also have no significant impact.

Results from the Eastern Interconnect Reliability Assessment Group–MRWS Inter–regional study show that SPP export capabilities are projected to be adequate for the upcoming summer with no significant limitations found up to the test transfer level. Import capabilities into SPP are adequate for firm transfers however they are limited from the East due to the Danville (Entergy)–Magazine (AEPW) 161 kV transmission line for the outage of the Ft. Smith (Oklahoma Gas and Electric)–ANO (Entergy) 500 kV transmission line. These transmission elements have a higher loading in the base case used for this study due to the modified MISO dispatch and nature of the MMWG cases that are used. SPP and Entergy do not observe this high of loading within internal models for upcoming operating conditions. This Entergy element limits imports into SPP from the East. However, imports from the North (MRO, MISO West) have no significant transmission constraints.

Approved in early 2007, the 2006 SPP Transmission Expansion Plan (STEP) has incorporated several changes from the previous Transmission Expansion Plan. The major change is the Planning Process has been changed from a two–year to a one–year process. This change helps to synchronize the SPP Transmission Expansion Plan models and the SPP Aggregate Study models. The shorter planning cycle will allow identifying reliability projects in a timelier manner. In order to track the status of projects, SPP has taken a strategic initiative called Project Tracking by which the transmission owners and SPP interact on a quarterly basis throughout the year until the completion of each project. For those projects which cannot be completed on time and hence cannot meet the in–service dates, SPP requests a mitigation plan for the affected project by the transmission owner. The mitigation plan is then subjected to review by the SPP staff.

The 2006 STEP dates from January 2006 though December 2016 and the total estimated cost of projects for this period is $ 1.4 billion. These projects include reconductoring 762 miles of line, converting operating voltages on 296 miles of line, construction of 1,392 miles of new line, and installing 1,998 Mvar of capacitors and 83 new or upgraded transformers. A list of the proposed major 345 kV transmission projects for the 10 year horizon is listed below along with their respective in–service dates & owners.

- June 2007 – AEPW to convert 22 miles of 138 kV to 345 kV transmission between the Wekiwa substation to Riverside substation in the Tulsa area.
- June 2008 – AEPW to construct 14 miles of 345 kV transmission between the Chamber Springs substation to Tontitown substation in northwest Arkansas.
- June 2010 – AEPW to construct 22 miles of 345 kV transmission between the Flint Creek generating station to the East Centerton substation in northwest Arkansas.
- June 2010 – Westar Electric (WERE) to construct 40 miles of 345 kV transmission between the Wichita to either Reno County or McPherson (final destination substation to be determined) substation in central Kansas.
- January 2011 – WERE to construct 51 miles of 345 kV transmission between either the Reno County or McPherson (final destination substation to be determined) to Summit substation in central Kansas.
- June 2013 – AEPW to construct 80 miles of 345 kV transmission between the Diana substation to Barton’s Chapel substation in northeast Texas.
- June 2013 – Southwestern Public Service Company (SPS) to construct 130 miles of 345 kV transmission between the Potter County Interchange substation to Roosevelt substations in the Texas Panhandle (northwest Texas).
- June 2015 – Sunflower Electric Power Corporation (SUNC) and Western Farmers Electric Cooperative (WFEC) to construct 140 miles of 345 kV transmission between the Spearville substation, located in southwest Kansas, to the Mooreland generating station, located in northwest Oklahoma.
- June 2015 – SPS and WFEC to construct 240 miles of 345 kV transmission between Mooreland generating station, located in northwest Oklahoma, to Potter County Interchange substation, located in the Texas Panhandle (northwest Texas).

As of this writing, there have been no nuclear plant generation interconnection requests and none are scheduled for construction in the next ten years. SPP is conducting a Competitive Renewable Energy Zones (CREZ) study to identify potentially beneficial transmission expansion projects that leverage existing SPP and ERCOT infrastructure and expansion plans to collect and deliver renewable energy from the Texas Panhandle. Called the X Plan or EHV Study, SPP has also contracted industry leaders to conduct a strategic assessment regarding long–term reliability and the economic need for a 345 kV, 500 kV, 765 kV, or higher voltage transmission system to overlay the SPP footprint. More information regarding these studies may be found on the SPP website, www.spp.org.

Before the August 14, 2003 blackout, transmission planning was on intra–regional basis and was limited to the individual operational boundaries of transmission owners rather than regional boundaries. SPP started its regional planning process, the SPP Transmission Expansion Plan (STEP), in 2003. The present STEP covers the entire SPP footprint and has a vision over a ten–year time horizon. Transmission projects are specifically listed and tracked on a quarterly basis by SPP staff.

Operational Issues

As previously stated, there are no known environmental or regulatory restrictions that are expected to impede reliability during peak loading periods.

Currently, no major generator unit or transmission outages affecting reliability in an adverse manner are anticipated over the next ten years for SPP. 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's standards.

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

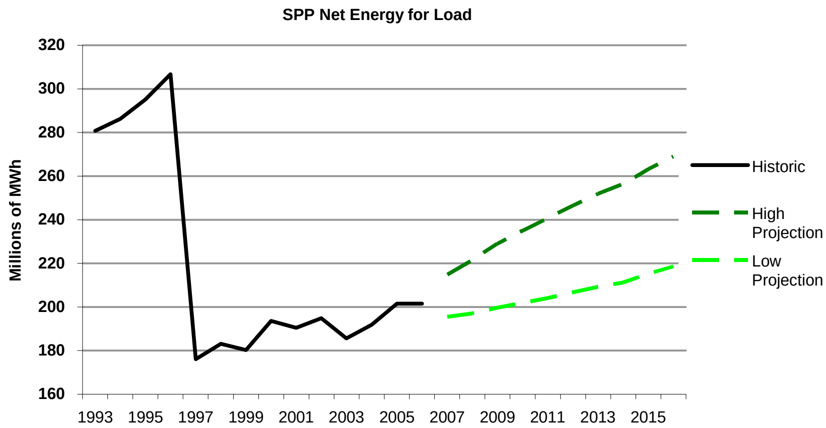
SPP has operated a reliability coordination center since 1997. The reliability coordination center provides the exchange of near real-time operating information and around-the-clock reliability coordination. SPP has experienced TLR curtailments on its transmission facilities in recent years and expects 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. The most notable change since the August 14, 2003 Blackout is the successful launch of SPP's Energy Imbalance System (EIS) Market Operations this year. The EIS should help consumers use some of the most efficient electricity in the nation.

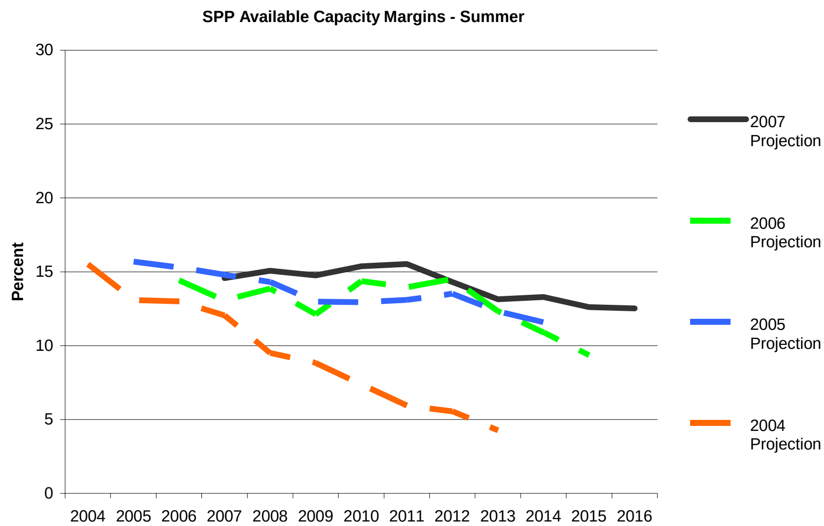
Region Description

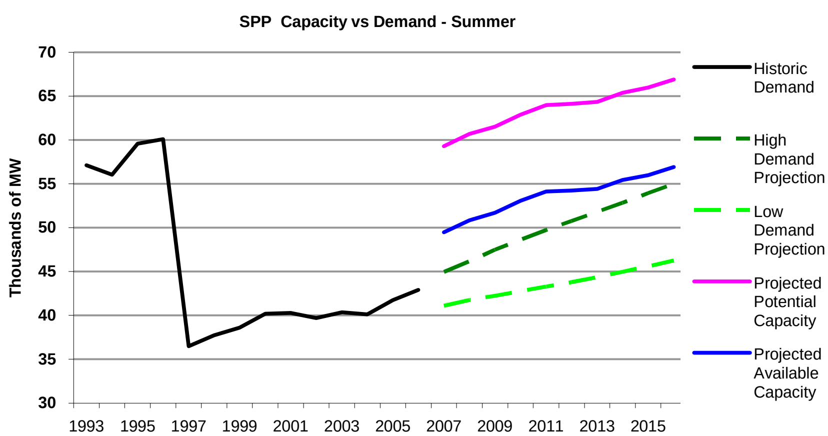
Southwest Power Pool (SPP) has 49 members that serve over 4.5 million customers. Our diverse membership consists of 13 investor–owned utilities, 11 generation and transmission cooperatives, 11 power marketers, 7 municipal systems, 3 independent power producers, 2 state *authorities, and 2 independent transmission companies. More than 350 electric industry employees on various organizational groups bring together industry wide expertise to deal with tough reliability and equity issues. A technical and administrative staff of over 250 persons facilitates the organization's activities and services. Primary or contract–based services provided to SPP Members and Customers are: Tariff Administration, Reliability Coordination, Regional Scheduling, Market Operations, and Transmission Expansion Planning. Helping our members work together to keep the lights on … today and in the future is our mission.*

SPP, primarily a summer peaking region, covers a geographic area of 255,000 square miles and has members in eight states: Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. SPP manages transmission in seven of the above states. SPP's footprint includes 17 balancing authorities and 52,301 miles of transmission lines. Additional information can be found on the SPP Web site (www.spp.org).

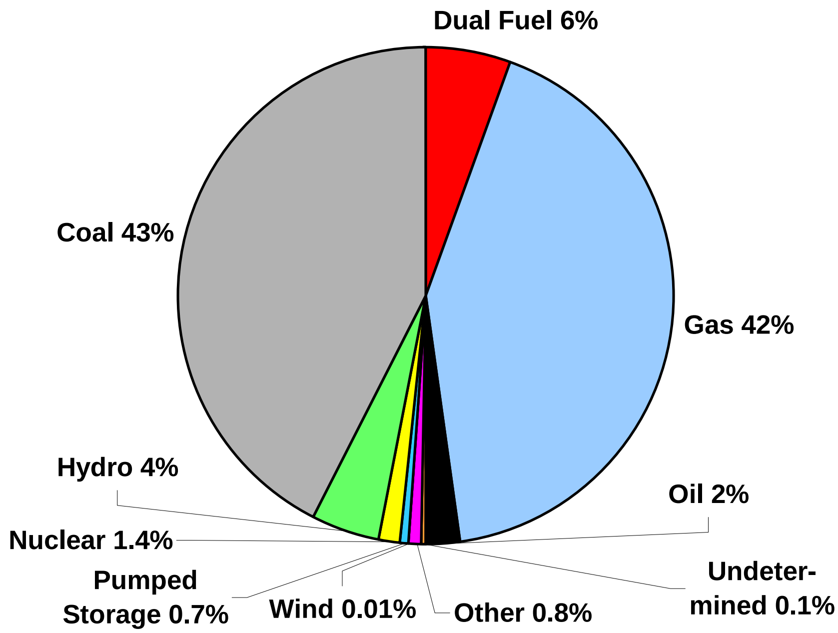
SPP Capacity and Demand



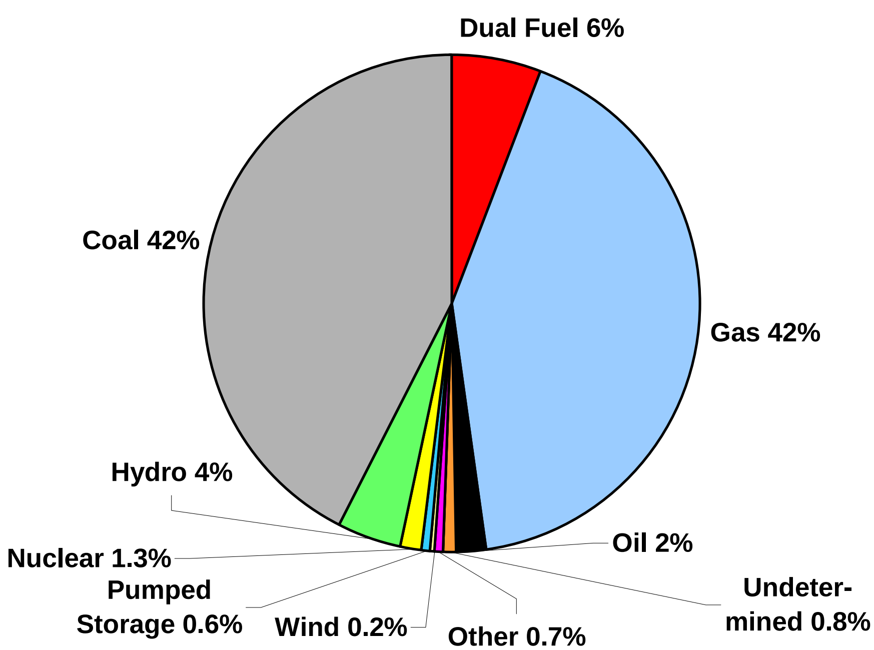




SPP Capacity Fuel Mix 2006



SPP Capacity Fuel Mix 2012



WECC

Peak Demand and Supply

Total actual internal demand increased by 8.0 percent from 2005 to 2006. Summer temperatures in 2006, which were much warmer than normal, influence the expected 2.6 percent decline from 2006 actual demand of 161,131 MW to projected 2007 summer total internal demand of 156,988 MW. Thereafter, summer total internal demand is expected to increase by about 2.0 percent per year compared to 2.2 percent projected last year for 2006-2015.

Demand response and interruptible loads range from 3,675 MW in 2007 to 4,212 MW by 2016. Most of the interruptible load is in California, which ranges from 2,671 mw in 2007 to 2,986 MW in 2016. A portion of the California demand response has been reduced to reflect actual load reduction experience. Much of the demand response in WECC is based on air conditioner cycling programs. Interruptible load programs are more focused on large water pumping operations and large commercial operations such as mining.

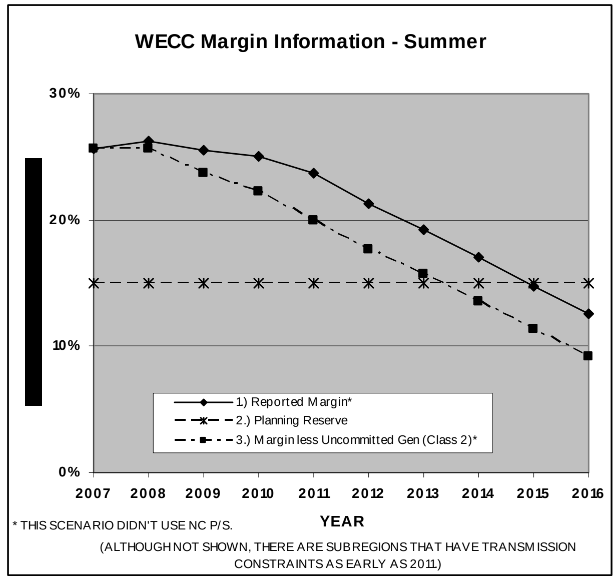
WECC's *2006 Power Supply Assessment Report* indicated that summer peak demands might increase region-wide by about 2,100 MW above the forecasted 2006 peak and about 2,530 MW above the forecasted 2015 peak, should the region experience a hot spell similar to that experienced on July 9, 1985. For the winter period, a region-wide increase of almost 2,570 MW in 2006-2007 to about 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 is in the process of establishing an interconnection-wide assessment metric to address the issue of peak demand uncertainty and especially variability in demand due to weather, the latter by incorporating coverage of 1-in-10 temperature stresses into the planning margin used for assessment. Individual entities within the interconnection have also 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.

Annual energy usage increased by 3.7 percent from 831,570 GWh in 2005 to 862,357 GWh in 2006. The 2006 energy usage was 2.6 percent more than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2006 through 2016 is forecasted to increase by 1.9 percent compared to the historic annual energy usage increase of 1.8 percent from 1996 through 2006.

Resource Adequacy Assessment

The WECC resource data is reduced to reflect non-metered self-generation and expected wind and hydro limitations. The data for the LTRA is provided by all of the balancing authorities within the Western Interconnection and is processed by WECC's Staff under the direction of WECC's Loads and Resources Subcommittee (LRS). This year, the LRS chose to categorize resource additions into three classes. Class 1 (committed) resources are defined as all resources presently under active construction (or committed for re-rating) with expected in-service dates before January, 2011 and totals 8,603 MW (summer capacity). Class 2 is composed of primarily uncommitted resources and is an additional 6,153 MW (summer capacity) reported as currently undergoing regulatory approval and will have an in-service date before January, 2013. Class 3 contains a total of 34,020 MW of resources that generally have an identified location but do not fall into the previous two categories.



Although not shown in the above graphic, there are North-South transmission constraints that begin in 2011 that affect the RMPA, AZ-NM-SNV and the California-Mexico region.. A graphic at the end of this section indicates the locations of the North-South constraints.

The Class 3 set of resources is not shown on the graphics, because it is considered by WECC's LRS to be too speculative at this time. Additional proposed projects without identified locations and/or in-service dates are excluded from the data. WECC intends the Class 3 designation to highlight the need for investment in the future and/or the need for further development of demand-side or supply-side resources. As the need for more capacity grows closer, projects that are considered Class 3 or are currently unknown should become more active and thus their status will change, which in turn will advance to Class 1 or 2.

The resource data for the individual subregions include transfers between subregions that are either firm or non-firm potential economic transfers with a high probability of occurring. These non-firm potential economic transfers reflect the potential utilization of seasonal demand diversity between the winter-peaking northwest and the summer-peaking southwest, as well as other economy and short-term firm purchases that are expected to be available in the western market. These potential transactions, internal transfers within the region, were simulated in WECC's *2007 Power Supply Assessment Report (PSA)* and are shown as non-contracted purchases in the subregion al graphs that follow in this report. The modeling for the PSA is performed using a least cost dispatch program called the Supply Adequacy Model (SAM) which considers transmission line limitations, basic transmission costs and losses and generation costs. Despite the fact that these transactions are currently not contracted, they have a high probability of occurring, given the history of the Western market and the otherwise underutilized northwest to California transmission. In order to simulate the results of the 2007 PSA, the various bubbles used in the PSA were combined into the appropriate WECC subregions (see diagram after Transmission Assessment section) and the excess capacity as reported by SAM was summed for each of the WECC subregions. The excess capacity was then used to help determine the amount of Non-Contracted Purchases or Sales (NC P/S) or transactions between the various subregions. The Reported Margin in the graphics shows Class 1 and Class 2 resources and Non-Contracted Purchases or Sales (except as noted in the graph).

Use of seasonal demand diversity may be limited due to factors such as internal transmission constraints. For example, Canadian winter imports from the U.S. portion of the Northwest Power Pool are assumed to be limited to 2,000 MW for the analysis currently being undertaken for WECC's *2007 PSA Report*. A 300 MW 230-kV transmission line has been proposed that would interconnect Montana and Alberta. That interconnection would increase the 2,000 MW limit.

For the summer of 2007, WECC entities report firm purchases from Eastern Interconnection entities of 612 MW, partially offset by firm sales of 245 MW. By the summer of 2016, purchases decline to 467 MW and sales decline to about 225 MW.

In WECC's preliminary analysis for the 2007 PSA report, summer transfer capability limitations between the northern and southern portions of the Western Interconnection could occur as early as 2009 when using only Class 1 generation and by 2011 when using both Class 1 and Class 2 generation. In the summer of 2011, three of the four WECC subregions show that their reserves are below their planning reserve margin. These transfer capability limitations could leave generation that is available in the northern portion unable to meet short-term loads in the southern region. *(Note, however, that due to energy constraints on operation of the hydro system in the Northwest, much of this surplus would be unavailable to meet multi-hour load requirements, including transfers to other regions of WECC)*. Although the transmission limitations represented in the PSA analysis are conservative, they are not unreasonable and the report establishes that WECC presently has insufficient transmission to fully utilize seasonal capacity/demand diversity within the Western Interconnection. There are several transmission projects that are in the conceptual stage which have been proposed that would help reduce future transmission constraints, while extending to areas of future renewable resource projects. Some of these conceptual projects are mentioned in the transmission section below.

In summary, resources described in this report are in three classes composed of 8,603 MW of committed resources in Class 1, 6,153 MW of resources in some stage of regulatory approval in Class 2 and 34,020 MW of additional identified resources in Class 3. The shortfall in planning reserves in the California-Mexico (CA-MX), Rocky-Mountain Power Area (RMPA) and Arizona - New Mexico - Southern Nevada (AZ-NM-SNV) is due to the intentional exclusion of Class 3 resources, the lack of Class 1 or 2 resources being built and congestion on the North – South Intertie. There are several options to address this problem: 1) add more resources locally, 2) further develop demand-side resources, and/or 3) increase the transfer capability from North to South to support the CA-MX, RMPA and AZ-NM-SNV areas. Increasing the transfer capability alone, however, would not be enough as there could be severe energy limits associated with the hydro resources in the Northwest.

The regulatory and financial status of many of the Class 3 projects is not known at this time. Because of the internal transmission limitations on transfers within the Western Interconnection and significant energy limitations on hydroelectric resources, it is misleading to make capacity-adequacy inferences based on a WECC-wide margin. Hence, margin graphics are provided for each of the four WECC subregions. It should also be noted that transmission limitations within the four subregions may preclude available resources from being delivered to load in major population centers due to local delivery constraints.

Fuel Supply & Delivery

WECC has not implemented a formal fuel supply interruption analysis method and does not consider such conditions in any 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 almost no 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. Individual entities may 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. Introduction of LNG supplies to the Western Interchange (WI) supply mix later this decade will add a new set of fuel supply complexities. WECC does not impose fuel supply requirements on its members.

Transmission Assessment

Transmission facilities are planned in accordance with NERC and WECC planning standards. These 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 intra-regional transfer capability constraints.

Planning Authorities and the Transmission Planners are responsible for ensuring that their areas are compliant with the TPL Standards 001 through 004. When the Planning Authorities and the Transmission Planners have created their datasets and successfully run their simulations, they forward their data to the WECC (the Regional Entity). WECC's System Review Working Group (SRWG) compiles and develops a WECC-wide base case under TPL-005-0 which is used for the WECC Annual Study Program. (A general comparison of the LTRA data to the data used for the TPL-005-0 studies is provided in a table after this section.)

The Annual Study Program provides base cases for WECC members and WECC staff, and provides an ongoing reliability and risk assessment of the existing and planned western interconnected electric system for the next ten years. To achieve this goal in 2006, ten new power flow base cases were compiled and thirty-five disturbances were simulated. Five power flow cases were prepared to conduct operating studies and the remaining five prepared to simulate various planning scenario cases through 2016. Disturbance simulations emphasize multiple contingency (N-2) outages (units and branches). Severe disturbances are simulated including loss of entire substations and entire generating plants to identify potential deficiencies leading to unacceptable system performance. The intent is to model system performance under stressed conditions with contingencies that might not normally be considered in operations and long term planning studies to identify potential concerns requiring further investigation.

If the 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.

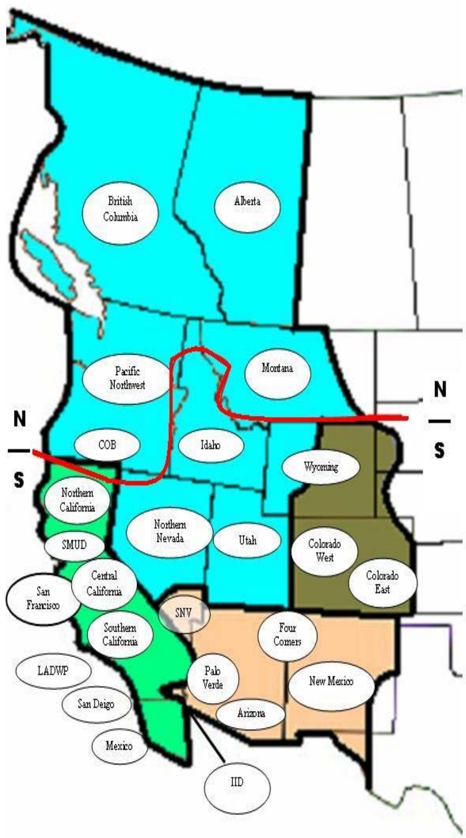
In conjunction with the Midwest Reliability Organization (MRO) and the Southwest Power Pool, Inc (SPP), WECC studies intra-area power transfer capabilities.

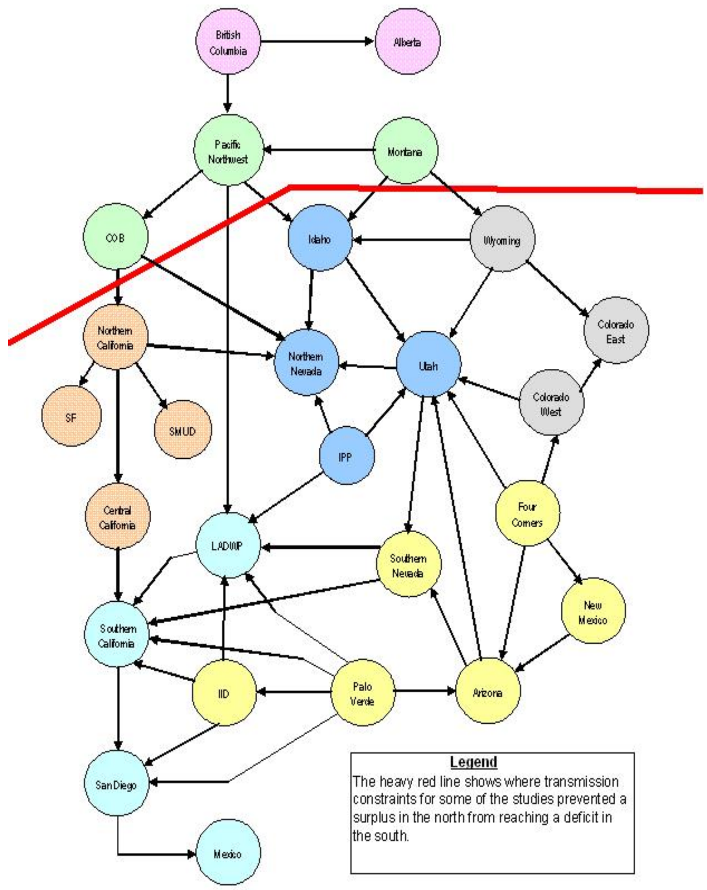
The U.S. Department of Energy (DOE) announced the issuance of two draft National Interest Electric Transmission Corridor (National Corridor) designations in early 2007. One of two proposed National Corridors is in the Southwest area of WECC and is called the Southwest Area National Corridor which includes counties in California, Arizona, and Nevada. WECC's Transmission Expansion Planning Policy Committee (TEPPC) has commented to the DOE that "TEPPC is not advocating for or against the draft corridors". The Energy Policy Act of 2005 authorizes the DOE, based on the findings of DOE's National Electric Transmission Congestion Study (Congestion Study), to designate National Corridors. The DOE issues draft National Corridors in order to encourage a full consideration of all options available to meet local, regional and national electric demand, which includes more local generation, transmission capacity, demand response, and energy efficiency measures.

In May of 2007, the Arizona Corporation Commission (ACC) denied a permit for Southern California Edison Company's (SCE) proposed Palo Verde–Devers 2 transmission project (going from Southern Arizona to Southern California). This project resides within the draft National Corridor and may be under further review depending on SCE's decision whether to appeal the denial or to take it to the Federal Energy Regulatory Commission (FERC) for review. The Palo Verde-Devers 2 transmission project was anticipated to be approved and was included in all of WECC's studies. If this project does not go forward, Southern California and the desert southwest will be impacted to a greater degree than shown in these studies.

In addition to the currently planned transmission projects, there have been several mega-transmission projects proposed. Some of these are the Northern Lights – Celilo Project (Alberta to Oregon), the Northern Lights – Inland Project (from far north as Montana to as far south as Los Angeles and Phoenix), the Frontier Line (from Montana and Wyoming to California), the TransWest Express Project (from Wyoming to Arizona), the Canada/Pacific Northwest to Northern California Study, and several others. These projects range from 1,500 to 3,000 MWs of transfer capability. One of the considerations is a 650 mile, 1,600 MW undersea DC cable that has been proposed to interconnect a substation near Portland, Oregon, and the San Francisco Bay area. These projects and others are in the early stages of being considered and are not included in this assessment. They are only mentioned for informational purposes. Most of these projects would be associated with potential renewable energy projects and reinforcing the transmission system but would help reduce future North-South transmission constraints.

During the study period, entities within WECC plan to add 8,111 miles of transmission lines rated 230-kV and above and includes 488 miles of 500-kV DC transmission lines. *Note: Some of the transmission projects contributing to the 8,111 miles of transmission lines may be associated with some of the Class 3 generation projects that were otherwise excluded from this assessment.*





The graphic on the left indicate the general boundaries and line paths associated with the term "North-South" constraint/congestion. The graphic on the right is from the WECC PSA report.

The below table shows the correlation of MWs from the Class 1, 2 and 3 resources compared to the resources used in the WECC Annual Study Program (simulation studies).

	2017 Power Flow Data Sum (Pmax)	**NERC's LTRA Planning Case** Class 1 & 2 resources but excluding Class 3	Excluding "Indefinitely Postponed (IP)" projects but including Class 3	Raw LRS data excluding "new gen" data pre-2007 (Filtered)	Raw LRS data including postponed projects
Class 1		8,603	8,603	8,603	8,603
Class 2		6,153	6,153	6,153	6,153
Class 3		0	34,020	37,274	41,903
Total New Generation		14,756	48,776	52,030	56,659
Existing Generation		192,850	192,850	192,850	192,850
Total LRS Data	**249,184**	**207,606**	241,626	244,880	**249,509**
LRS data / FERC715 data		83.31 %	96.97%	98.27%	100.13%

Operational Issues

Under WECC's current 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 2003 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.

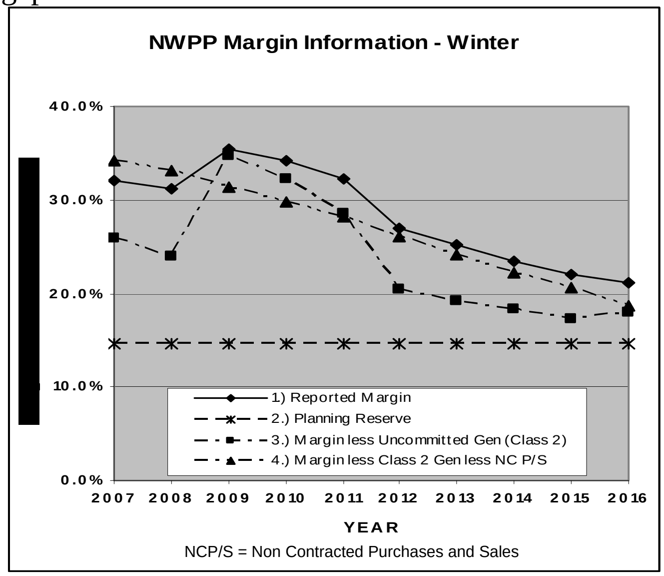
WECC operations personnel are progressing on implementing an interconnected system operating condition model.

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.

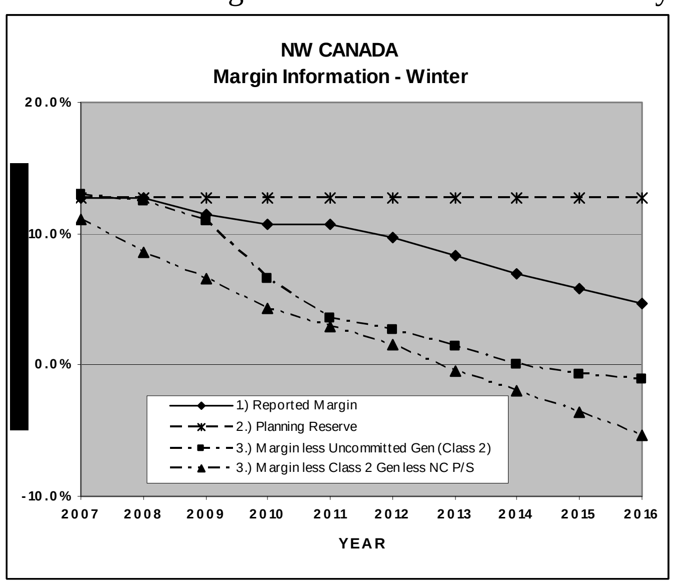
Northwest Power Pool Area

Peak Demand and Energy — 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 2007 through 2016, winter total internal demands are projected to grow at annual compound rates of 1.5 percent and 1.8 percent in the United States and Canadian areas, respectively. The gap in the summer of 2016 between total internal demand plus target margin and the resources, both committed and undergoing regulatory review (Class 1 and 2) is 3,813 MW or 10,545 MW without future Non-Contracted sales. The gap in the winter season of 2016-2017 including Class 1 and 2 is 4,605 MW or 4,893 MW without future Non-Contracted sales. Annual energy requirements are projected to grow at annual compound rates of 1.6 percent and 2.2 percent in the U.S. and Canadian areas, respectively.



WECC's *2006 Power Supply Assessment Report* indicated that summer peak demands might 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. As noted earlier, the 2007 PSA will incorporate coverage of weather stress events into the planning reserve margin.

Annual energy usage increased by 2.2 percent from 360,889 GWh in 2005 to 368,894 GWh in 2006. The 2006 energy usage was 0.7 percent greater than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2006 through 2016 is forecast to increase by 1.7 percent compared to the historic annual energy usage increase of 1.0 percent from 1996 through 2006. Annual energy requirements are projected to grow at annual compound rates of 1.5 percent and 2.1 percent in the U.S. and Canada areas, respectively.



Resource Adequacy Assessment — The data for the United States portion of the NWPP present winter 2007/2008 reserve margins of 47.0 percent without any Class 2 generation or non-contracted transactions (purchases or sales) and 40.9 percent with those resources (Reported Margin). Much of the WECC's forecast surplus capacity margin exists due to the Columbia River

Basin hydroelectric dams located in the NWPP-US, but deliverability to other areas is problematic due to both the constrained North-to-South transfer capability and the limited energy associated with the hydro storage. By winter 2012/2013, those margins change to 39.2 percent and 39.3 percent, respectively. *(Note, due to energy constraints on the operation of the hydro system in the Northwest, much of this surplus would be unavailable to meet multi-hour load requirements, including transfers to other regions of WECC)*. For the Canadian portion of the NWPP the winter planning reserve margin is 12.8%. In the winter of 2007/2008 reserve margins are 11.0 percent without any Class 2 generation or non-contracted transactions and 12.8 percent with those resources. If the non-contracted transactions are included with the Class 1 resources, it would postpone the deficit one year. The first year that the subregion goes deficit with Class 2 resources and non-contracted transactions would be the winter of 2009-10. Due to transmission constraints within Canada, by the winter of 2012/2013, those margins decline to 1.5 percent without any Class 2 generation or non-contracted purchases/sales and 9.7 percent with those 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 94 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 Northwest Power and Conservation Council has adopted resource adequacy assessment standards for the Pacific Northwest (PNW) portion of the subregion (representing approximately 25 percent of the load), which consists of the states of Oregon, Washington, Idaho, and a portion of Montana. The adopted energy and capacity-adequacy standards are both tied to probabilistic analyses targeting a loss of load probability of 5 percent or less. The remaining portions of the subregion have not established a formal 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 Supply & Delivery — 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 the costs and options for integrating wind. Careful and site-specific assessments are needed to minimize adverse consequences that may occur. Interconnection queues already limit addition of intermittent resources.

Transmission Assessment — 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 1,074 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 2008.

The second approval is for the construction of a 500-kV line, approximately 330 kilometers (200 miles) in length, to strengthen the main Alberta north-south transmission grid. This development has a proposed in-service date of 2009.

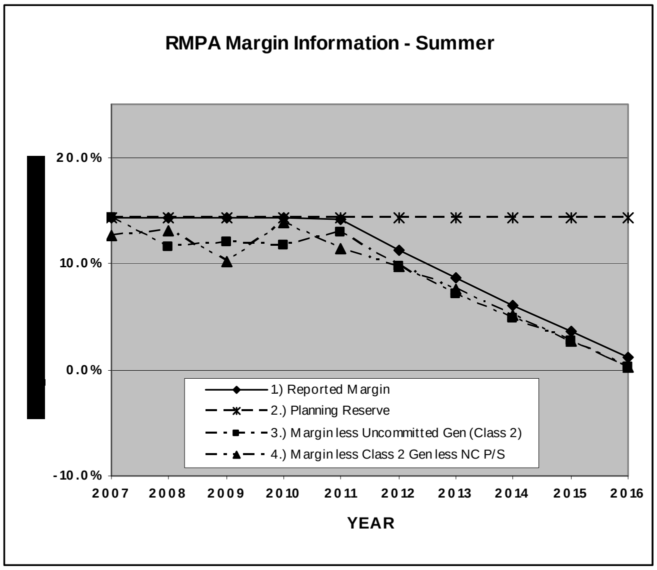
A Calgary area transmission must run (TMR) procedure addresses 240-kV transmission grid-loading issues and ensures that voltage stability margins are maintained. The TMR service is an ancillary service contract with generators that is required to address contingencies in areas of inadequate transmission 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 July 2007. 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 Transmission Corporation (BCTC) is responsible for the planning, operation, and maintenance of British Columbia's publicly-owned transmission system. BCTC is addressing constraints between remote hydro plants and lower mainland and Vancouver Island load centers. The definition phase of reinforcing the Interior to Lower Mainland (ILM) transmission grid is underway. One of the reinforcement options is building a new 500-kV line between Nicola and Meridian substations by 2014. Regulatory approvals for a 230-kV underwater cable between Arnott substation and Vancouver Island terminal have been obtained. The expected in-service date of the project is 2008. The ILM reinforcement project 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
Benewah, ID to Shawnee, WA 230-kV line	Under way	2007
American Falls, ID to Hunt, ID 230-kV line	Under way	2007
Keephills-Genesee-Ellerslie, AB 500-kV line	Under way	2007
Goose Lake to N. Lethbridge, AB 230-kV line	Permitting	2008
Montana-Alberta 230-kV merchant line	Permitting	2008
Vancouver Island-Arnott 230-kV line	Planning	2008
Genesee, AB to Langdon, AB 500-kV line	Permitting	2009
Britnell, AB to Wesley Creek, AB 240-kV line	Planning	2010
Ely, NV to Las Vegas, NV	Planning	2010
Mona, UT to Salt Lake, UT 345-kV line	Planning	2007/2010
Cranbrook, BC to Invermere, BC 230-kV line	Planning	2011
West of McNary Generation Integration Project	Planning	2012
I-5 Corridor Reinforcement 500-kV (70 miles)	Planning	2013
Nicola, BC to Meridian, BC 500-kV	Planning	2014

Operational Issues — 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.

Preliminary analysis for WECC's 2007 PSA report indicates that transmission constraints exist between the United States and Canadian portions of the NWPP and that by 2016 over 2,500 MW of additional capacity (generation or transmission for imports) will be needed in Canada. Both provinces are addressing the capacity issue.



Rocky Mountain Power Area

Peak Demand and Energy — 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 2007 through 2016, summer total internal demands and annual energy requirements are projected to grow at annual compound rates of 2.3 percent and 2.4 percent, respectively. The gap in 2016 between total internal demand plus target margin and the resources, both committed and undergoing regulatory review (Class 1 and 2) is -1,822 MW

WECC's *2006 Power Supply Assessment Report* indicated that summer peak demands might not increase should the RMPA area experience a hot spell similar to that experienced on July 9, 1985. For the winter period, an increase of almost 50 MW in 2006-2007 to about an additional 60 MW in 2015-2016 may occur should the area experience a cold spell similar to that experienced on December 22, 1998. As noted earlier, the 2007 PSA will incorporate coverage of weather event stresses into the planning reserve margin.

Annual energy usage increased by 3.4 percent from 59,190 GWh in 2005 to 61,174 GWh in 2006. The 2006 energy usage was 1.8 percent greater than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2006 through 2016 is forecast to increase by 2.3 percent compared to the historic annual energy usage increase of 3.4 percent from 1996 through 2006. Annual energy usage for the nine-year period from 2007 through 2016 is forecast to increase by 2.4 percent.

Resources — The RMPA planning reserve margin is 14.25% for the summer and 15.37% for the winter. The data for the Rocky Mountain Power Area (RMPA) present the summer 2007 reserve margins of 12.6 percent without any Class 2 generation or non-contracted purchases and 14.2 percent with those resources (Reported Margin). However, if you included non-contracted purchases with the Class 1 resources the reserve margin doesn't go below its planning reserve margin until July 2009 and then it is 13.5%. The first time the reserve margin goes below the planning reserve margin with the Class 2 resources and non-contracted purchases is in July of 2011, where there is a shortfall of 5MW which produces a margin 14.21%. (The 5MW would usually be ignored but is pointed out in this case since all other subregions also have a shortfall in July 2011). By the summer of 2012, the margin of Class 1 with non-contracted purchases becomes 10.3 percent and the margin with Class 1 and 2 and non-contracted purchases 11.3 percent as depicted in the margin information graphic. A significant portion of the expected uncommitted resources have received state utility commission approval and are under active development.

Public Service Company of Colorado (PSC) has a 750 MW coal-fired plant under construction at the existing Comanche station with an expected in-service date of 2010. PSC is preparing to begin a new resource planning cycle in October 2007 when it will file its next least-cost resource plan with the Colorado Public Utilities Commission.

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 Supply and Delivery — 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.

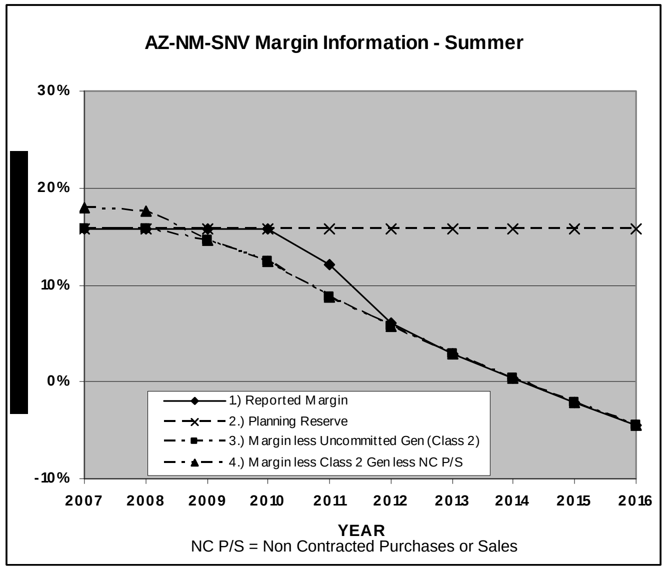
Transmission Assessment — The Western Area Power Administration (WAPA) plans to upgrade several 115-kV transmission lines to 230 kV over the next ten years to increase transfer capabilities and help maintain the operating transfer capability between southeastern Wyoming and northeastern Colorado. In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

Proposed RMPA Projects > 50 Miles	Status	In-service Date
Walsenburg, CO to Gladstone, NM 230-kV line	Completed	Dec. 2006
Donkey Creek, WY to Pumpkin Buttes, WY 230-kV	Planned	Nov 2008
Hughes, WY to Sheridan, WY 230-kV line	Planned	2009
San Luis Valley-Walsenburg, CO 230-Kv line	Planned	2009
Upgrades to Path 36 (TOT3) between southeast Wyoming and northeast Colorado	Under way	2009
Midway, CO to Wateron, CO 345-kV line	Planned	May 2009
Comanche-Daniels Park #1 & #2 345-kV lines	Planned	May 2010
Beaver Creek-Erie #2 230 kV line	Under way	2010
Holcomb, KS to Front Range, CO 345 & 500-kV lines	Planned	2012

Operational Issues — 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 used to preserve system adequacy should multiple outage contingencies occur.

Arizona-New Mexico-Southern Nevada Power Area

Peak Demand and Energy — 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 2007 through 2016, summer total internal demands and annual energy requirements are projected to grow at annual compound rates of 2.6 percent and 2.7 percent, respectively. The gap in 2016 between total



internal demand plus target margin and the resources, both committed and undergoing regulatory review (Class 1 and 2) is 7,646 MW.

WECC's *2006 Power Supply Assessment Report* indicated that summer peak demands might increase by about an additional 45 MW in 2006 to about 55 MW in 2015 should the area 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. As noted earlier, the 2007 PSA will incorporate coverage of weather stresses into the planning reserve margin.

Annual energy usage increased by 6.6 percent from 126,540 GWh in 2005 to 134,950 GWh in 2006. The 2006 energy usage was 4.0 percent greater than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2006 through 2016 is forecasted to increase by 2.6 percent compared to the historic annual energy usage increase of 3.6 percent from 1996 through 2006. Annual energy usage from 2007 through 2016 is forecast to increase by 2.7 percent.

Resource Adequacy Assessment— The AZ-NM-SNV planning reserve margin is 15.7% for the summer and 14.6% for the winter. The data for this sub-area present the summer 2007 reserve margins of 17.9 percent without any Class 2 generation or non-contracted purchases and 15.7 percent with those resources (Reported Margin). If you include the non-contracted purchases with the Class 1 resources the margin would be 15.7% and doesn't go below the planning reserve until July 2009 where it drops to 12.7%. The first time the reserve margin goes below the planning reserve margin with the Class 2 resources and non-contracted purchases is in the July of 2011, where there is a shortfall of 1,225 MW which produces a margin 12.2%. By the summer of 2012, those margins become 5.7 percent and 6.0 percent, respectively, as depicted in the margin information graphic.

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. The margin information graphic for the area demonstrates the subregion faces a somewhat limited window of opportunity to address area resource adequacy issues. Frequently, resource acquisitions, including load reduction options, are subject to a request for proposal process that may increase the uncertainty regarding plant type, location, etc. These factors combine to make resource adequacy forecasting problematic over 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 Supply and Delivery — 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 Assessment — Transmission providers from the AZ-NM-SNV Power area have been and 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. The STEP group has developed three projects resulting 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 was completed in 2006 and increased the transfer capacity by 505 MW. 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 and is reported in the California-Mexico power area table.

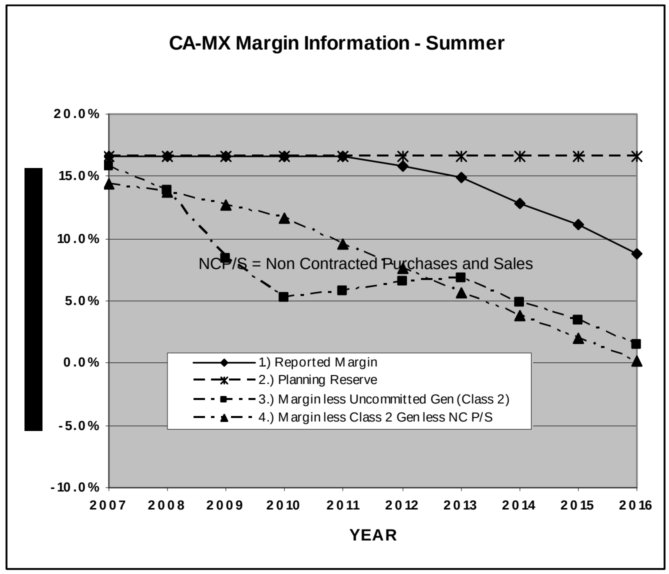
As mentioned earlier, the Department of Energy (DOE) has also studied various areas of congestion and identified the desert southwest as an area of concern and has proposed the Southwest Area National Corridor which includes counties in California, Arizona, and Nevada. The third set of upgrades as proposed by the STEP group has developed complications with the Arizona Corporation Commission's refusal to grant a permit for the construction of the Palo Verde to Devers #2 (PVD2) line. This may cancel or delay the construction of the PVD2 line. As the above AZ-NM-SNV margin graphic depicts, the desert southwest region drops below their planning reserve margin as early as 2009 without purchasing additional Non-Contracted energy from outside of their subregion or building additional generation. By 2011, the AZ-NM-SNV region will potentially be below their minimum reserve margin although there appears to be available transmission surrounding Arizona. The table below outlines some of the ongoing transmission projects that are past the conceptual stage and considered in this assessment:

Proposed AZ/NM/SNV Projects > 50 Miles	Status	In-service Date
Harry Allen, NV to Mead 500-kV line	Complete	Jan 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	2008 - 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
Four Corners, NM to Marketplace, NV 500-kV line	Permitted	2010/2011
Pinal South -Tortolita, AZ 500-kV line	Planning	2011
TS5-Raceway 500-kV line	Planning	2012
Palo Verde-North Gila 500-kV line	Planning	2012
Northern to central New Mexico 345-kV generation outlet lines	Planning	2013
Nogales, AZ to Sahuarita, AZ 345-kV lines	Planned	2014

Proposed AZ/NM/SNV Projects > 50 Miles	Status	In-service Date
Greenlee-Springerville, AZ #2 345-kV line	Planning	2015
Tucson, AZ area 345-kV reinforcements	Planning	2015

Operational Issues — 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



Peak Demand and Energy — 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 1.5 percent and 5.6 percent in the United States and Mexican areas, respectively, from 2007 through 2016. Annual energy requirements are projected to grow at annual compound rates of 1.3 percent and 5.2 percent in the U.S. and Mexican areas, respectively. The gap in 2016 between total internal demand plus target margin and the resources, both committed and undergoing regulatory review (Class 1 and 2) is (Class 1 and 2) is 5,358 MW – which doesn't account for importing 1,375 MW of non-contracted purchases. Of the 34,020 MW of Class 3 generation, 24,540 MWs are projected for the California-Mexico Area (but are not included in any of the graphics or calculations). California generally peaks in August, but first shows going below its planned reserve margin in July of 2011, and yet it meets its planned reserve margin during its peak month of August of 2011. This may be attributed to WECC having its regional peak in July, so there is less capacity available for non-contracted purchases.

WECC's *2006 Power Supply Assessment Report* indicated that summer peak demands might increase in the area 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 in the area 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. As noted earlier, the 2007 PSA will incorporate coverage of extreme weather events into the planning reserve margin.

Annual energy usage increased by 4.3 percent from 284,951 GWh in 2005 to 297,339 GWh in 2006. The 2006 energy usage was 4.6 percent greater than the forecast in last year's assessment, due to generally warm to hot weather conditions throughout much of the year. Annual energy usage for the ten-year period from 2006 through 2016 is forecasted to increase by 1.7 percent compared to the historic annual energy usage increase of 1.8 percent from 1996 through 2006.

Annual energy usage for the nine-year period from 2007 through 2016 is forecast to increase by 1.4 percent.

Resource Adequacy Assessment — The California-Mexico total area (CA-MX) planning reserve margin is 16.6% for the summer and 12.8% for the winter. The planning reserve margin for California is 16.7% and 12.8% for the summer and winter respectively. The planning reserve margin for Baja Mexico is 14.7% and 12.9% for the summer and winter respectively. The data for the United States portion of the California-Mexico sub-area present summer 2007 reserve margins of 14.5 percent without any Class 2 generation or non-contracted purchases (Line 4 on the graphic) and 16.7 percent with those resources (Line 1 on the graphic). If you include the non-contracted purchases with the Class 1 resources, the margin would be 15.7% and doesn't go below the planning reserve until August of 2009 where it drops to 12.7%. California generally peaks in August, but when using both Class 1 and 2 resources and non-contracted purchases, it first shows going below its planned reserve margin in July of 2011, a non-peak month, where there is a shortfall of 1,225 MW which produces a margin 12.2%. But in 2011, CAMX meets its planned reserve margin for its peak month of August for that year. This may be attributed to WECC having its regional peak in July, so there is less capacity available for non contracted purchases during that month. In the summer of 2012, California does peak in July and those margins become 9.7 percent and 16.2 percent, respectively, as depicted in the margin information graphic. For the Mexican portion of the subregion, the summer of 2007 reserve margins are 12.4 percent without any Class 2 generation or non-contracted purchases and 14.7 percent with those resources. If the non-contracted purchases are included with the Class 1 resources, the margin would be 14.7% and doesn't go below the planning reserve until July of 2011 where it drops to 11.7%. By summer 2012, those margins become 5.8 percent and 5.8 percent, respectively.

It should be noted again, that in July of 2011, the three subregions in the southern portion of the WECC is projected to be below their planning reserves due to the lack of Class 1 or 2 resources being built in those subregions and also congestion on the North – South Intertie in the Pacific Northwest region.

In 2016, the shortfall between the load plus planned margin versus the projected resources is 5,358 MW – which doesn't account for importing 1,375 MW of non-contracted purchases. Of the 34,020 MW of Class 3 generation, 24,540 MWs are projected for the California-Mexico Area (but are not included in any of the graphics or calculations).

Uncertainty surrounding resource acquisitions in California has raised questions regarding future projections of generating capacity. For example, five years ago over 45,000 MW of planned resource additions were reported for the area for the 2002–2011 ten-year period (this included Class 3). Two years ago the assessment reported a decrease to 6,783 MW for the 2005-2014 period. This year's assessment reports an increase to 7,433 MW (Class 1 and 2) for the 2007–2016 period compared to 3,160 MW reported last year for the 2006–2015 period.

California has implemented a mandatory resource adequacy program for the California ISO (CAISO) load control area requiring load serving entities to procure 115% of their forecast demand 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.

Fuel Supply and Delivery — 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*[139] identifies eight key actions to address natural gas supply, demand, and infrastructure.

Transmission Assessment — 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. With the Arizona Corporation Commission's May 2007 denial of SCE's Palo Verde – Devers #2 permit, SCE will need to appeal the ACC's decision or readdress their resource plan. 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.

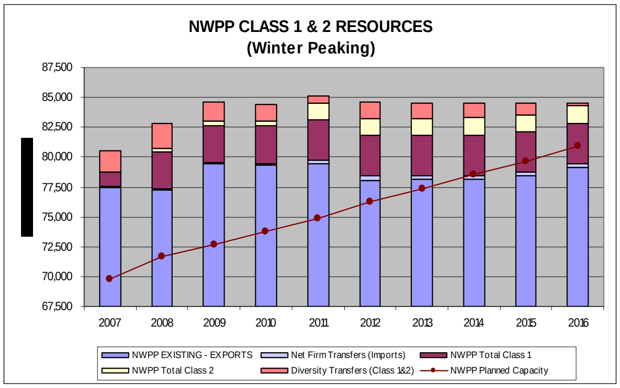
Proposed CA/MX Projects > 50 Miles	**Status**	**Date**
La Jovita Project, MX 230-kV lines	Planning	2009
Palo Verde-Devers #2 500-kV line	Permitting	2009
Imperial Valley-San Diego 500-kV line	Planning	2010
Indian Hills-Upland 500-kV line	Planning	2010
New Vincent-Mira Loma 500-kV line	Planning	2011
Tehachapi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

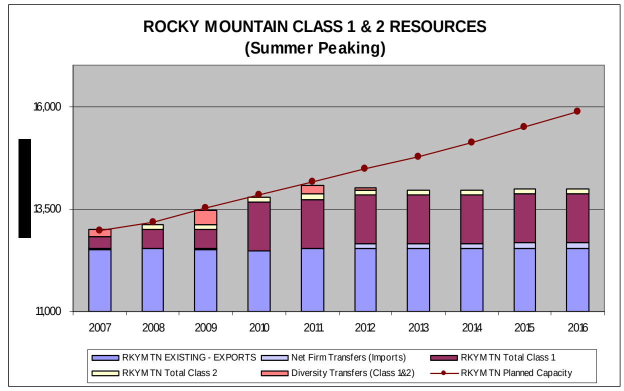
Operational Issues— The CAISO is moving forward on a Market Redesign and Technology Upgrade (MRTU) program of changes to ISO market and grid operations. The CAISO has set a March 2008 launch date for the MRTU program, which includes upgrades to the CAISO's computer technology to a scalable system that can grow and adapt to future system requirements. Transmission upgrades in the area have alleviated some transfer capability limitations, but numerous system constraints remain.

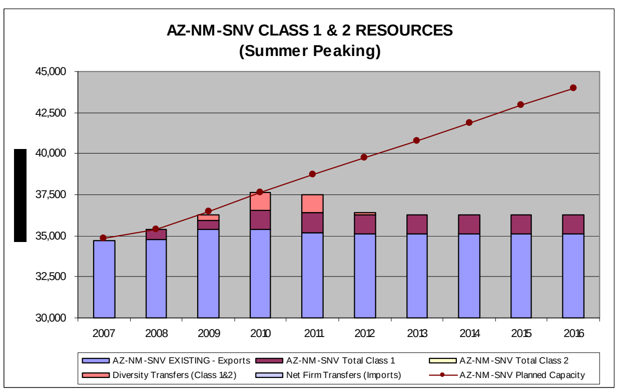
Operator flexibility is limited by the transmission constraints and is further impacted by forest and brush fires that often occur during high-demand periods. The CAISO and other entities within the subregion are interacting in developing an integrated transmission plan for the state to address significant constraint issues.

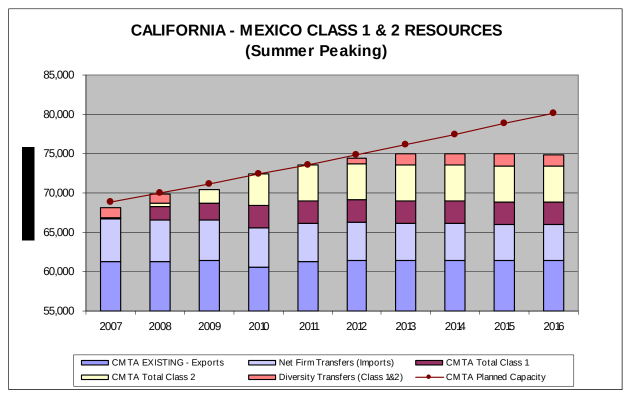
[139] http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF

Overall Resources

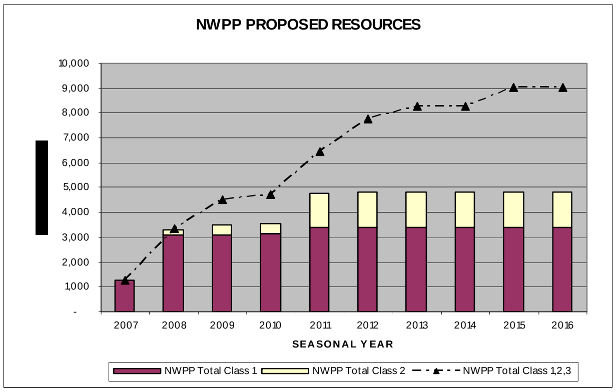


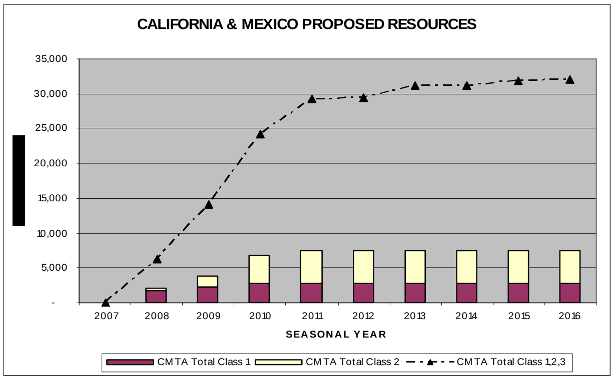


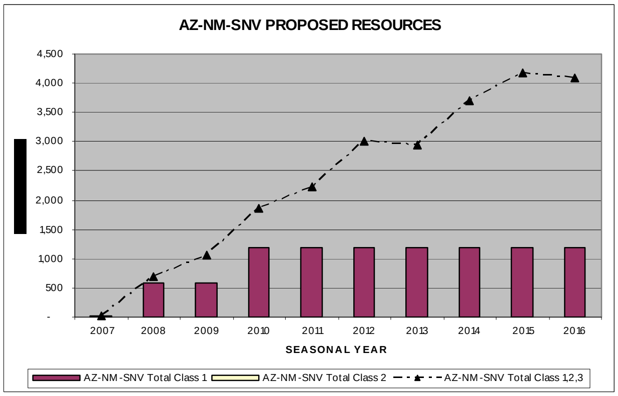


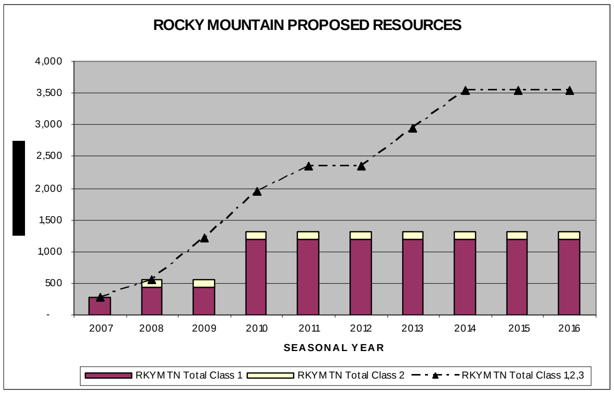


It should be noted, that although not clear on the above graphics, all three of the summer peaking subregions have a shortfall below their planning reserve margin in July of 2011. The California-Mexico Subregion's peak in 2011 is in August and is able to import enough non-contracted purchases to meet its planning reserve margin for that month, but not for July.





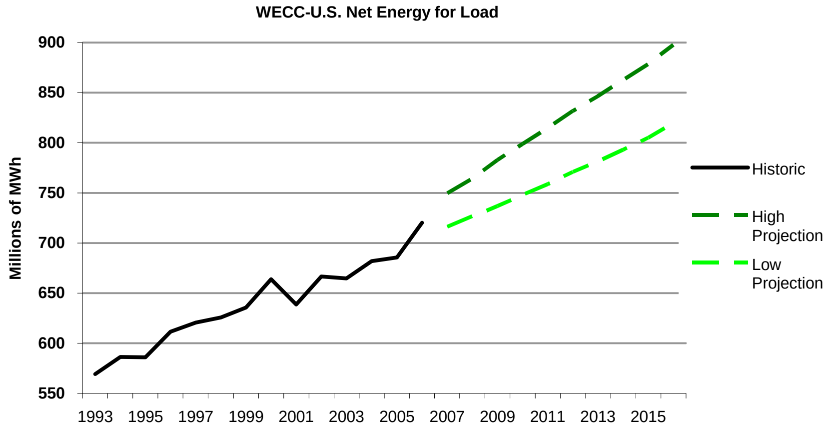


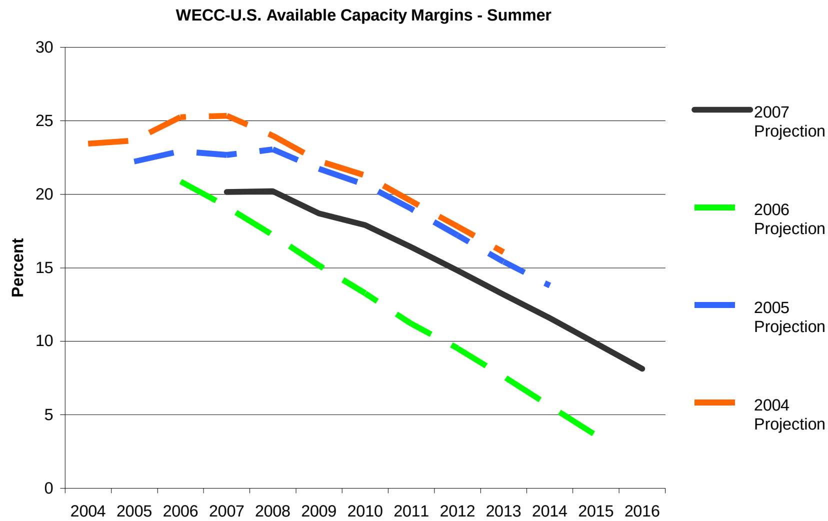


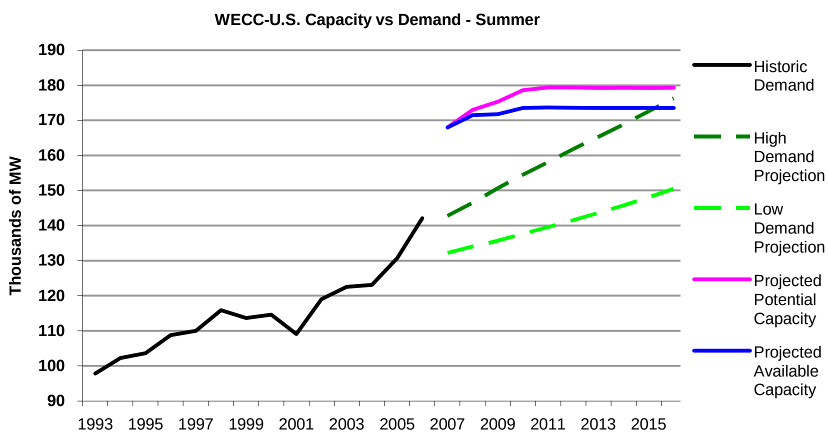
Region Description

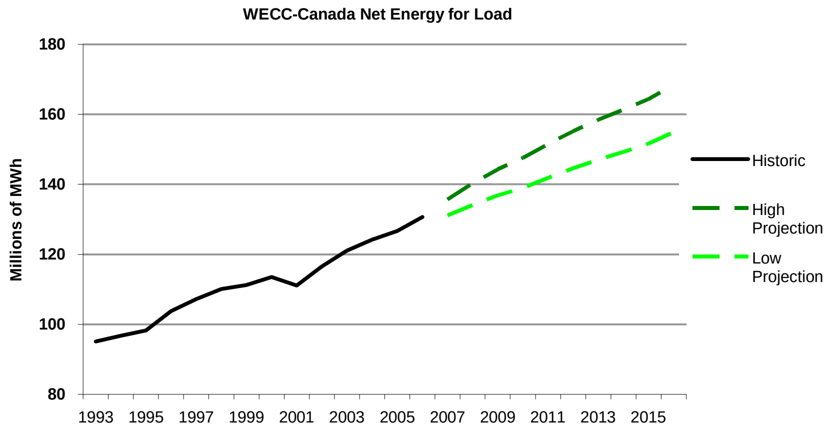
WECC's 189 members represent the entire spectrum of organizations with an interest in the bulk power system. Serving an area of nearly 1.8 million square miles and 71 million people, it is the largest and most diverse of the eight NERC regional entities. The WECC region is spread over a wide geographic area with significant distances between load and generation areas. In addition, the northern portion of the region is winter peaking while the southern portion of the region is summer peaking. Consequently, transmission constraints are a significant factor affecting economic grid operation in the region. However, reliability in WECC is best examined at a subregional level. Additional information can be found on the WECC Web site (www.wecc.biz).

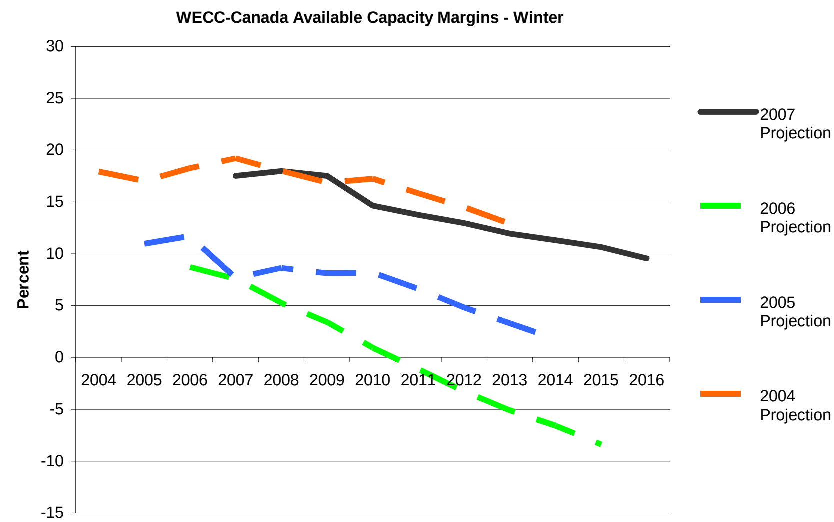
WECC Capacity and Demand

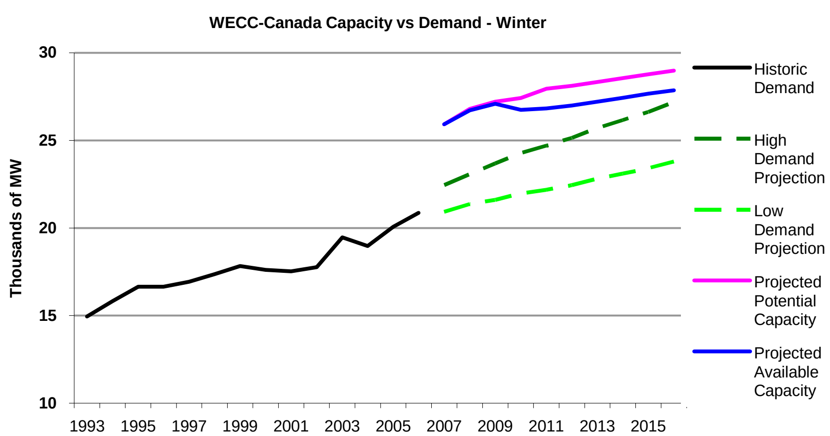


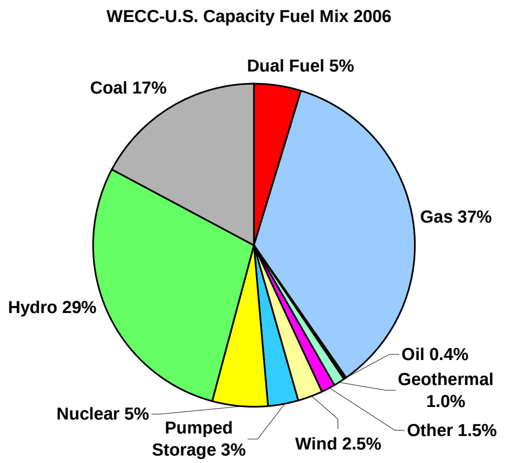


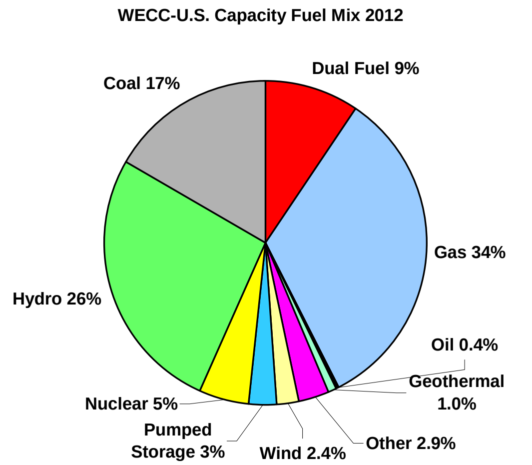


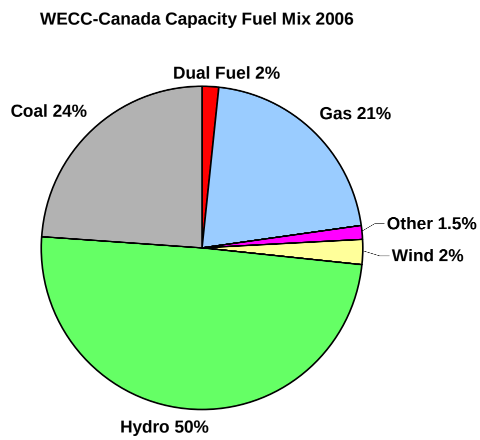

WECC-Canada Net Energy for Load
Millions of MWh
180
160
140
120
100
80
1993 1995 1997 1999 2001 2003 2005 2007 2009 2011 2013 2015
Historic
High Projection
Low Projection

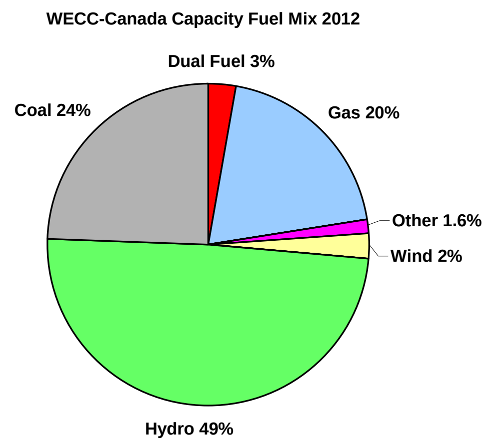

WECC-Canada Available Capacity Margins - Winter
Percent
30
25
20
15
10
5
0
-5
-10
-15
2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016
2007 Projection
2006 Projection
2005 Projection
2004 Projection


WECC-Canada Capacity vs Demand - Winter
Thousands of MW
30
25
20
15
10
1993 1995 1997 1999 2001 2003 2005 2007 2009 2011 2013 2015
Historic Demand
High Demand Projection
Low Demand Projection
Projected Potential Capacity
Projected Available Capacity


WECC-U.S. Capacity Fuel Mix 2006
Dual Fuel 5%
Coal 17%
Gas 37%
Hydro 29%
Oil 0.4%
Geothermal 1.0%
Nuclear 5%
Pumped Storage 3%
Wind 2.5%
Other 1.5%


WECC-U.S. Capacity Fuel Mix 2012
Dual Fuel 9%
Coal 17%
Gas 34%
Hydro 26%
Oil 0.4%
Geothermal 1.0%
Nuclear 5%
Pumped Storage 3%
Wind 2.4%
Other 2.9%


WECC-Canada Capacity Fuel Mix 2006
Dual Fuel 2%
Coal 24%
Gas 21%
Other 1.5%
Wind 2%
Hydro 50%


WECC-Canada Capacity Fuel Mix 2012
Dual Fuel 3%
Coal 24%
Gas 20%
Other 1.6%
Wind 2%
Hydro 49%

Appendix I: 2007-2016 Major Transmission Projects (>200 kV) by NERC Regional Entity

Project Name	Voltage (kV)	Length (Miles)	In-service Date(s)	Description/Status
ERCOT				
San Miguel – Lobo 345 kV	345	110	04/2010	New line to serve reliability needs of Laredo, Texas
Clear Springs–Salado Project	345	127	08/2011	Line from economic generation in central Texas through several load centers to the north
TNP One to Bell County	345	40	12/2010	New line to reduce congestion related to new coal generation
FRCC				
Intercession City-West Lake Wales #2	230	30	06/2010	New line in the Central Florida area
Intercession City-West Lake Wales #1	230	30	06/2011	Rebuild existing line in the Central Florida area
RFC				
Trans-Allegheny Interstate Line (TrAIL)	500	210	2011	New RFC-SERC interconnection from 502 Junction to Mt. Storm, Mt. Storm to Meadow Brook, and Meadow Brook to Loudoun. Will relieve anticipated overloads and voltage problems in the Washington, DC area.
Potomac-Appalachian Transmission Highline (PATH)	765	250	2012	John Amos substation in western West Virginia to the Bedington substation in eastern West Virginia. This project will relieve possible future overloads in Washington, DC, Pennsylvania, Maryland, West Virginia, Virginia and even New Jersey.
Potomac-Appalachian Transmission Highline (PATH)	500	80	2012	Two 40-mile 500kV circuits will connect Bedington to a new substation in Kemptown near the Doubs-Brighton and Brighton-Conastone 500 kV lines outside of Washington, DC. This project will relieve possible future overloads in Washington, DC, Pennsylvania, Maryland, West Virginia, Virginia and even New Jersey.
Susquehanna to Lackawanna	500	130	2012	130-mile 500 kV transmission line from Susquehanna to Lackawanna in Pennsylvania, and on to Jefferson and ending at Roseland in northern New Jersey. This line will resolve overloading problems on 23 existing facilities in Pennsylvania and New Jersey
PAR-controlled Scott – Bunce Creek B3N circuit	230	-	2009	The Scott – Bunce Creek B3N circuit on the Michigan-Ontario interface is expected to be fully controlled by phase angle regulators (PARs). The PARs are intended to improve the ability to manage power flow around Lake Erie.
Black Oak SVC	500	-	2008	A Static VAR Compensator (SVC) is planned for the Black Oak substation near the Maryland-West Virginia border. This SVC addresses post-contingency low voltages (reactive limit) for west to east transfers.
Bismarck to Troy	345	15.4	2009	Creates a Bismarck-Troy 345 kV line that includes a Troy 345/120 kV transformer.
Gibson to AB Brown to Reid	345	40	2011	New RFC-SERC interconnection from Gibson (Duke Energy, RFC) to AB Brown (Vectren, RFC) to Reid (BREC, SERC).

	Project Name	Voltage (kV)	Length (Miles)	In-service Date(s)	Description/Status
WECC					
NWPP Projects	Part of the comprehensive West of Hatwai (WOH) transmission project - Benewah, ID to Shawnee, WA	230	60	2007	Complete 230 kV loop in the Moscow/No. Lewiston area.
	Borah – Hunt Project – American Falls, ID to Eden, ID	230	70	2007	Increase West of Borah transfer capability
	Southwest Alberta Reinforcement Project – Peigan, AB - North Lethbridge, AB – Goose Lake, AB	230	57	2007 - 2008	Reinforce SW Alberta transmission system and accommodate new wind generation development
	Part of the Olympic – Peninsula Project – Olympia, WA – Satsop, WA – Shelton, WA	230	48	2008	Part of the Olympic – Peninsula Project a.k.a. BPA G-12
	MATL Project – Montana-Alberta 230-kV merchant line	230	205	2008	Permitting -privately funded "Merchant" transmission line from Lethbridge, AB to Great Falls, MT for renewable resources & transfer capability
	Vancouver Island Transmission Reinforcement Project – Vancouver Island, BC – Arnott, BC	230	43	2008	Planning - Existing 138 kV overhead AC line will be replaced. This new circuit will consist of sections of 230 kV AC overhead line and submarine cables. The purpose is to replace the aging DC circuits between Arnott and the Vancouver Island Terminal.
	Part of Edmonton to Calgary Transmission Reinforcement - Genesee, AB to Langdon, AB	500	206	2009	Permitting - To meet load growth and import/export requirements.
	Northwest Alberta Reinforcement Project -Britnell, AB to Wesley Creek, AB	240	145	2010	Planning - Reinforce NW Alberta transmission system to meet load growth
	Ely, NV to Las Vegas, NV – Gonder - Harry Allen, NV	500	250	2010	Planning - SPPC / NPC intertie with White Pine County generation estimated rating of 2000 MW N-S
	Mona, UT – Camp Williams, UT, -to Salt Lake, UT 345-kV line	345	57	2007/2010	Planning - Line will increase capacity into Wasatch Front from existing and new resources
	East Kootenay Reinforcement Project -Cranbrook, BC to Invermere, BC	230	80	2011	Planning – To serve increased loads
	West of McNary Generation Integration Project – McNary, OR to Boise/Middleton, ID	230	231	2012	Planning
	I-5 Corridor Reinforcement 500-kV (70 miles)	500	70	2013	Planning
	Nicola, BC to Meridian, BC 500-kV	500	153	2014	Planning – To serve increased loads
RMPA Projects	Walsenburg, CO to Gladstone, NM 230-kV line	230	80	Dec. 2006	Completed – Increase transfer capability and access to resources
	Peetz Logan – Pawnee Project – Logan, CO – Pawnee, CO	230	70	Sept. 2007	Non-PSCo transmission to deliver 400 MW of wind generation to PSCo
	Cedar Creek-Keenesburg Project – Grover, CO – Keenesburg, CO	230	72	Dec. 2007	Non-PSCo transmission to deliver 300 MW of wind generation to PSCo
	Donkey Creek, WY to Pumpkin Buttes, WY 230-kV	230	75	Nov 2008	Planned
	Hughes – Sheridan 230-kV Project Hughes, WY to Sheridan, WY	230	105	2009	Planned
	San Luis Valley-Walsenburg, CO 230-Kv line	230	80	2009	Planned - Required to support San Luis Valley loads for the Poncha - San Luis Valley 230 kV line outage
	Upgrades to Path 36 (TOT3) Miracle Mile - Ault 203 kV line Project Cheyenne, WY – Miracle Mile, WY, Ault, CO	230	181	Dec 2009	Underway - Replace an existing 115 kV line. Correct declining voltage in the Laramie and Cheyenne areas
	Midway, CO to Wateron, CO 345-kV line	345	82	May 2009	Planned - Transmission to deliver 500 MW from Squirrel generation to Denver
	Comanche-Daniels Park #1 & #2 345-kV lines	345	250	May 2010	Planned - Transmission to deliver 750MW from Comanche Unit #3 to Denver metro area

	Project Name	Voltage (kV)	Length (Miles)	In-service Date(s)	Description/Status
WECC *(continued)*					
AZ/NM/SNV Projects	Part of Centennial Project – Harry Allen, NV to Mead, NV	500	50	Jan 2007	Capacity for 3000 MW to NPC, Navajo and Eldorado Valley includes Mead 525/230 #2
	Stirling Mt-Northwest-Vista, NV 230-kV line Vista, NV – Stirling, NV– Northwest, NV	230	41	2007	Planned- To meet increased loads and increase reliability
	Palo Verde-TS5 500-kV line Palo Verde, AZ – Phoenix, AZ	500	45	2009	Permitted - A new 500 kV line from Palo Verde to northwest of Phoenix (TS5 substation)
	Palo Verde to Southeast Valley (Phoenix area)			2008 - 2011	3 Parts
	A. Hassayampa to Pinal West Wintersburg, AZ – Mobile, AZ	500	51	2008	Under way - Terminates at Hassayampa
	B. Pinal West to Santa Rosa 500-kV line	500	13	2008	Under way
	C. Santa Rosa to Browning 500-kV line	500	87	2011	Permitted - New 500 kV line from Santa Rosa to Browning.
	Sunrise 500 kV Project – Las Vegas, NV area	230 500	42 16	2010	Planning - Capacity to meet Las Vegas load growth
	Centennial II (Las Vegas, NV area) 500-kV line	500	50	2011	Planning - Capacity for 2500 MW to NPC, Navajo and Eldorado Valley. Crystal - Harry Allen - Eldorado 500 kV line project.
	Navajo Transmission Project – Four Corners, NM - Marketplace, NV	500	469	2009 - 2011	Permitted - From the Navajo Indian Reservation, parallel the Glen Canyon - Flagstaff 345 kV Line and then parallel the Moenkopi - Eldorado 500 kV Line.
	Pinal South -Tortolita, AZ 500-kV line	500	30	2011	Planning - Capacity for Tucson load growth
	TS5-Raceway 500-kV line – Northwest of Phoenix, AZ – Peoria, AZ	500	40	2012	Planning – New 500 kV line
	Palo Verde-North Gila 500-kV line Wintersburg, AZ – Yuma, AZ	500	115	2012	Planning - A new 500 kV line for load growth. A participant project
	Northern to central New Mexico 345-kV generation outlet lines	345	71	2013	Planning
	Tucson, AZ area 345-kV reinforcements	345		2015	Planning
	Part of Centennial Project – Harry Allen, NV to Mead, NV	500	50	Jan 2007	Capacity for 3000 MW to NPC, Navajo and Eldorado Valley includes Mead 525/230 #2
CA MX Projects	La Jovita Project, MX 230-kV lines	230	50	2009	Planning
	Palo Verde-Devers #2 500-kV line	500	225	2009	Permitting SCE's project to reinforce and increase transfer capability
	Sunrise Powerlink – Imperial Valley-San Diego 500-kV line	500	120	2010	Planning – One 500kV line from Imperial Valley sub to new sub in Central San Diego, with series compensation.
	Green Path Los Angeles Connection – Indian Hills-Upland 500-kV line	500	100	2010	Planning will link two public power control areas and provide LADWP with access to renewable resources
	New Vincent-Mira Loma 500-kV line			2011	Planning
	Tehachapi Area Transmission — 500 kV	500	100	2010–2011	Pending – sponsored by SCE, PG&E and a consortium of wind generation developers

Region	Project Name	Voltage (kV)	Length (Miles)	In-service Date(s)	Description/Status
SPP					
	NW Arkansas Reliability Improvement	345	21	06/2011	New line from Flint Creek – East Centerton
	NW Arkansas Reliability Improvement	345	14	06/2008	New line from Chamber Springs – Tontitown
	Western Kansas Reliability Improvement	230	8	09/2007	New line from Knoll – South Hays
	Western Kansas Reliability Improvement	230	42	09/2007	New line from Heizer – South Hays
	New Mexico Reliability Improvement	230	34	06/2009	New line from Seven Rivers Intg. – Potash Jct.
	Texas Panhandle Reliability Upgrades	230	40	06/2010	New line from Hitchland – Prairie
	Texas Panhandle Reliability Upgrades	230	50	08/2010	New line from Hitchland – Moore Co.
	Texas Panhandle Reliability Upgrades	230	35	10/2010	New line from Hitchland – Pringle
	SPP "X" Plan	345	130	04/2012	New line from Potter – Roosevelt
	SPP "X" Plan	345	65	04/2012	New line from Tolk – Tuco
	SPP "X" Plan	345	280	04/2012	New line from Tuco – Mooreland
	SPP "X" Plan	345	140	04/2012	New line from Mooreland – Spearville
	Oklahoma-Kansas Reliability Improvement	230	21	11/2009	New line from Mustang – Seminole
	Oklahoma-Kansas Reliability Improvement	345	100	06/2011	New line from Rose Hill - Sooner
	Kansas Reliability Improvement Plan	345	35	12/2008	New line from Wichita – Reno County
	Kansas Reliability Improvement Plan	345	51	12/2009	New line from Reno County – Summit
	Kansas City Area Reliability Improvement	345	50	12/2010	New line from JEC – Swissvale
	SE Oklahoma Reliability Improvement	345	16	12/2010	New line from Hugo – Valliant
NPCC					
New England	numerous	various			The New England region has 253 transmission projects in various stages of planning, construction, and implementation. The ISO-NE and the transmission owners collaboratively conducted the studies that support these projects. ISO-NE "2006 Regional System Plan," dated October 26, 2006, identifies these projects (See http://www.iso-ne.com/trans/rsp/2006/rsp06_final_public.pdf).
New York	Mott Haven Substation	345-138	NA	in service	Mott Haven is a new 345 kV substation in New York City, between the Dunwoodie and Rainey substations, serving load in Bronx county, NY.
New York	Project Neptune	500	65 (51 under-water / 14 under-ground)	in service	The Neptune Regional Transmission System, LLC merchant transmission project is an HVdc interconnection between PJM and New York. The cable links the Sayreville 230 kV substation in New Jersey with the Newbridge Road 138 kV substation in the Long Island load area of New York state.
New York	Replacement of the Northport to Norwalk Harbor 138 kV Underwater Cable.	138	11	2008	The existing Northport to Norwalk Harbor 138 kV cable is an oil filled cable lying on the floor of Long Island Sound. It will be replaced by a dry dielectric cable buried beneath the seabed surface
New York	Rochester Area Substation Enhancements	345		2008	Study is underway
New York	Sprain Brook to Sherman Creek	345	10	2009	Study is underway
Quebec	Hawthorne, Ontario to Outouais, Québec	230	44	2009	1,250 MW back-to-back HVdc converters – Double Circuit
Quebec	Chenier to Outaouais	315	70.8	2010	
Quebec	Eastmain-1A to Eastmain-1	315	1.2	2010	
Quebec	Sarcelle to Eastmain-1A	315	68.8	2010	
Quebec	Romaine-2 to Arnaud	315	162.9	2014	Designed for 735 kV
Quebec	Romaine-1 to Romaine-2	315	19.1	2016	
Maritimes	Pt. Lepreau, NB to Orrington, ME	345	144	Dec. 2007	Increase transfer capability
Ontario	Hawthorne, Ontario to Outouais, Québec	230	44	2009	1,250 MW back-to-back HVdc converters – Double Circuit
Ontario	Bruce to Milton	500	220	2012	

Project Name	Voltage (kV)	Length (Miles)	In-service Date(s)	Description/Status
MRO				
Oak Creek to Hale (Brookdale) - Provisional, Support New Generation	345	25.2	2013	Construct an Oak Creek-Hale (Brookdale) 345-kV line installing 4 mi. new structures, converting 16.2 mi. of non-operative 230 kV and 5 mi. 138 kV
Hale (Brookdale) to Granville - Provisional, Support New Generation	345	15.6	2013	Construct a Hale (Brookdale)-Granville 345- kV line converting/reconductoring 5.6 mi. 138 kV, rebuilding 7 mi. 138 kV double circuit tower line and converting/ reconductoring 3 mi. 138 kV on existing 345-kV structures
West Middleton to North Madison- Proposed, Support Reliability	345		2016	Construct West Middleton-North Madison 345-kV line
Misaba Plant to Blackberry - Proposed, Support New Generation	345	9.0	5/1/2012	Rebuild 9 miles of existing line to double circuit 345 kV Lines to a capacity of 1200 MVA
Alexandria to Benton County - Proposed , Support Reliability	345	62.5	7/1/2012	Construct a new 62.5 mile 345 kV Line from Alexandria to Benton County with a capacity of 720 MVA
Maple River to Alexandria - Proposed , Support Reliability	345	100	7/1/2012	Construct a new 100 mile 345 kV Line from Maple River to Alexandria with a capacity of 720 MVA
SERC				
Carson-Suffolk	500	50	May-2011	Addition
Loudoun-Mt Storm	500	100	Jun-2011	Addition
Joshua Falls (AEP)-Lady Smith	500	85	Dec-2016	Addition
Cumberland-Montgomery	500	40	Jun-2008	Addition
Maury-Rutherford	500	27	May-2010	Addition
Thomson Primary-Vogtle	500	50	Jun-2015	Line to accommodate generation expansion at Vogtle.
Osierfield-Pine Grove	500	60	May-2012	Line to accommodate load growth in Valdosta/South Georgia. Project now postponed beyond the planning horizon.
East Walton-Rockville	500	40	Jun-2011	Line from central Georgia area resources to Atlanta area load.
Thomson-Warthen	500	35	Jun-2010	Line from central Georgia area resources to Augusta area load.
Bogue Chitto - Bogalusa	500	12	Jun-2012	Addition
Baldwin-Rush Island	345	28	June 2010	Line and Mississippi River crossing from the Baldwin Plant Switchyard in southwest Illinois to the Rush Island Plant Switchyard in eastern Missouri to alleviate congestion and ensure deliverability of new two-unit Prairie State 1650 MW coal-fired plant

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
ERO	Electric Reliability Organization
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
IROL	Interconnection Reliability Operating Limit
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kV	Kilovolts (thousands of volts)
LFU	Load Forecast Uncertainty
LNG	Liquefied Natural Gas
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 Corporation
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
PC	NERC Planning Committee
PJM	PJM Interconnection
PRB	Powder River Basin
PRSG	Planned Reserve Sharing Group
RAS	Reliability Assessment Subcommittee of NERC Planning Committee
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
SOL	System Operating Limit
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

Reliability Concepts Used in This Report

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. 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.

Committed Capacity Resources — Generating capacity resources that exist, 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.

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.

How NERC Defines Bulk Power System Reliability

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

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

Regarding **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.
- 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.
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5 percent).
- 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, rotating the outages among individual feeders.

Under the heading of **Security**, 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.

Forecast Bandwidths

Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities of a range of possible outcomes. Each regional demand projection, for example, is assumed to represent the expected *midpoint* of possible future outcomes. This means that a future year's actual demand may deviate from the midpoint projections due to the inherent variability of the key factors that drive electrical usage. In the case of the NERC regional projections, there is generally a *long-run* 50 percent probability that actual demand will be higher than the forecast midpoint and a *long-run* 50 percent probability that it will be lower.

For planning and analytical purposes, it is useful to have an estimate not only of the expected midpoint of possible future outcomes, but also of the distribution of probabilities around the projection. Accordingly, the LFWG develops upper and lower 10 percent confidence bands around the NERC region demand and energy projections. *This means that there is a long-run 80 percent probability that future demand and energy will occur within these bands.* Concurrently, there is a 10 percent chance that future outcomes could be less than the lower band and a 10 percent chance that future outcomes could be higher than the upper band.

OVERVIEW OF METHOD

The principal features of the regional bandwidth method include:

(1) A univariate time series model for each region (and selected subregions when applicable). The regional projections of demand and net energy for load are modeled as a function of past demand or energy.

(2) The regional time series models are structured as a first-order autoregressive process. This approach expresses the current value of the time series as a linear function of the previous value of the series and a random shock. In equation form, the first-order autoregressive model can be written as

$$y_t = \alpha + \phi_1 y_{t-1} + \varepsilon_t$$

Where α is a constant term and ϕ_1 is the autoregressive parameter which describes the effect of a unit change in y_{t-1} on y_t. The shocks ε_t are random errors or white noise and are assumed to be normally and independently distributed with mean zero, constant variance σ_ε^2, and independent of y_{t-1}.

(3) In cases where membership changes resulted in significant changes to a region's energy and load, an intervention variable is added to the equation to allow the bandwidths to suitably depict post-change energy and load uncertainty. The historic variability observed in demand and energy is used to develop uncertainty bandwidths for demand and energy projections. Variability, represented by the variance σ_ε of the historic data series, is combined with other model information to derive the uncertainty bandwidths unique to each regional projection.

Each of the 8 regions is modeled separately. To maintain past practice, each region (if applicable) is separated into its United States and Canadian segments. For each region, the irregular pattern of deregulation, an economy with extended periods of high and low growth and atypical weather patterns from time to time contribute to the variability of actual peak demand and electricity usage. The response to these factors within each region is inherently different due to dissimilarities in weather variation, economic conditions, energy prices and regulation/deregulation policies. The bandwidths around NERC regional projections of long-term peak demand forecasts implicitly reflect the combined uncertainty from these factors. Accordingly, the bandwidth results on a region-by-region basis are unique.

Reliability Assessment Subcommittee

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

Vince Ordax
FRCC Representative
Transmission Planning Engineer
Florida Reliability Coordinating Council

Hoa Nguyen
MRO Representative
Resource Planning Coordinator
Montana–Dakota Utilities Co.

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

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

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

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

Mak Nagle
SPP Representative
Manager, Transmission
Southwest Power Pool

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

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

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

Dan Woodfin
ERCOT Representative
Director, System Planning
Electric Reliability Council of Texas, Inc.

John Lawhorn
ISO/RTO Representative
Director, Regulatory and Economic Standards
Transmission Asset Management
Midwest ISO, Inc.

Sedina Eric
FERC Representative
Electrical Engineer, Reliability Division
Federal Energy Regulatory Commission

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

Christopher Plante
MRO Alternate
Director, Transmission Analysis
WPS Resources Corporation

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

Poonum Agrawal
DOE Liaison
Manager, Markets and Technical Integration
U.S. Department of Energy

Mark G. Lauby
Manager, Reliability Assessment
North American Electric Reliability Corporation

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

Cheri Thompson
Administrative Assistant
North American Electric Reliability Corporation

Errata

25 October 2007

Page 31: Regional Highlights Section: Ontario

After the self assessment materials were provided to NERC, a report planned for submission to the Ontario Energy Board, was delivered. Further, Ontario Power Authority (OPA) projects the retirement of all coal fired units by 2014 in this report. This section, second and, third paragraph, is updated to record this action prior to 16 October 2007.

Page 84: Emerging Issues Section: Nuclear

The third paragraph is revised to remove incorrect information about building new nuclear power in Ontario. Further, the second sentence related to Bruce Power replaced the word "rebuild" to "refurbish" and added "in Ontario" after "two reactors" to improve locational context. The third line, of this same paragraph, now ends at "Lake Huron."