NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2010 Long-Term Reliability Assessment

to ensure the reliability of the bulk power system

October 2010

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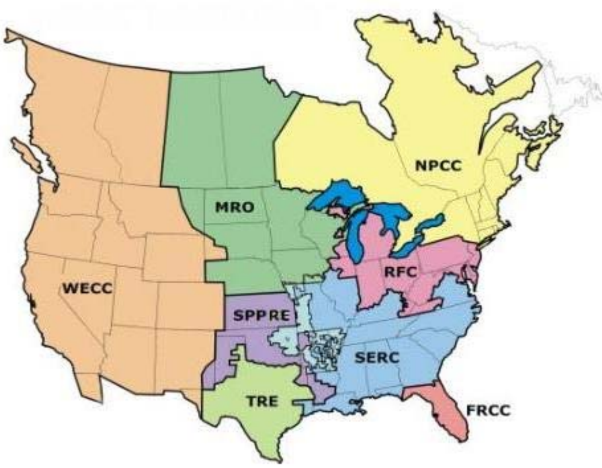
NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses reliability annually via a 10-year assessment and winter and summer preseasonal assessments; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas as shown on the map below and listed in Table A. 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 Norte, México.



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

Table A: NERC Regional Entities

FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP RE** Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	**TRE** Texas Reliability Entity
RFC Reliability*First* Corporation	**WECC** Western Electricity Coordinating Council

[1] 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. users, owners, and operators of the BPS, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have frameworks in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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Executive Summary

The reliable delivery of electricity to North American homes and businesses is a critical element of North Americans' way of life. Through the Energy Policy Act of 2005, the United States Congress charged the North American Electric Reliability Corporation (NERC) with developing annual long-term assessments to report the state of reliability of the bulk power system. NERC is under similar obligations to many of the Canadian provinces.

NERC's annual ten-year reliability assessment, the *Long-Term Reliability Assessment*, provides an independent view of the reliability of the bulk power system, identifying trends, emerging issues, and potential concerns. NERC's projections are based on a bottom-up approach, collecting data and perspectives from grid operators, electric utilities, and other users, owners, and operators of the bulk power system.

The electric industry has prepared adequate plans for the 2010-2019 period to provide reliable electric service across North America. However, many issues may affect the implementation of these plans. This report discusses the key issues and risks to bulk power system reliability. Highlights of this report include:

- THE ECONOMIC RECESSION, WHICH BEGAN AFFECTING DEMAND PROJECTIONS IN 2009, AND CONTINUED ADVANCEMENT OF DEMAND-SIDE MANAGEMENT LEADS TO DECREASED DEMAND PROJECTIONS AND HIGHER OVERALL RESERVE MARGINS.
- AN UNPRECEDENTED, CONTINUING CHANGE IN THE GENERATION FUEL MIX IS EXPECTED DURING THE NEXT TEN YEARS, WHICH INCLUDES SIGNIFICANT INCREASES IN NEW GAS-FIRED, WIND, SOLAR, AND NUCLEAR GENERATION.
- VITAL BULK POWER TRANSMISSION DEVELOPMENT BEGINS TO TAKE SHAPE, STREGNTHENING THE BULK POWER SYSTEM AS WELL AS INTEGRATING THE HIGH LEVELS OF PROJECTED VARIABLE GENERATION.
- CROSS-INDUSTRY COMMUNICATION AND COORDINATION IS KEY TO SUCCESSFUL PLANNING AND MEETING THE OPERATIONAL NEEDS OF THE FUTURE.

The electric industry is anticipating a wide variety of both Demand-Side Management and generation resources to reliably supply projected peak demand in North America. On the demand side, industry is able to implement Energy Efficiency, conservation, and Demand Response programs to effectively manage both peak and overall energy use. Supply projections rely on the enhanced performance and upgrading of existing units, addition of new resources (mostly wind, gas, and nuclear), and the purchase of electricity from neighboring systems. However, like all plans, these options are not without risk. It is up to industry, policymakers and regulators to thoroughly understand and manage these risks to ensure bulk power system reliability in North America.

PROGRESS SINCE 2009

In the *2009 Long-Term Reliability Assessment*,[2] NERC identified five key findings and that could affect long-term reliability, unless actions were taken by the electric industry. NERC's key findings in 2009 were based on observations and analyses of supply and demand projections submitted by the Regional Entities, NERC staff independent assessment, and other stakeholder input and comments.

The magnitude of these issues necessitates complex planning and effective strategies whose effects may not be realized for several years. As shown in Table A, while much progress has been made on the 2009 Emerging Issues, continued action is still needed on all of the issues identified in last year's report to ensure a reliable bulk power system for the future. NERC continues to monitor and assess these issues based on industry progress through the *Reliability Issues* section of this report and special reliability assessments.

Table A: Progress on 2009 Key Findings

2009 Key Finding	*Economic Recession, Demand-Side Management Lead to Decreased Demand, Higher Reserve Margins*	*Significant New Renewable Resources Come Online*	*Natural Gas Expected to Replace Coal as the Leading Fuel for Peak Capacity by 2011*	*Transmission Siting and Construction Must Accelerate To Meet Plans and Ensure Reliability*	*Industry Faces Transformational Change*
Progress in 2010	Issued 2010 Scenario Reliability Assessment: Potential Reliability Impacts of Swift Economic Recovery	Issued 5 Reports on the Integration of Variable Generation	Several industry studies probe the potential of gas and impacts of fuel-switching	NERC collected data on current transmission project delays and the causes of these delays	Issued two Special Reliability Assessments Reliability Impacts: •Climate Change Initiatives •Smart Grid
2010 Status	•Recession effects continue to impact demand forecast. •2010 Key Highlight	•Integration of Variable Generation Task Force to develop recommendations •2010 Key Highlight	•Trend continues in 2010 •2010 Key Highlight	•Transmission development should continue as planned.	•Annual risk assessment •Smart Grid Task Force to work on recommendations
Industry Progress	Industry continues to develop Demand-Side Management Programs as well as measurement and verification standards	Interconnection-wide planning groups develop coordinated strategies for transmission analysis and planning efforts	New gas capacity in 2010 represents largest single-fuel increase used for on-peak generation in North America	Progress shown in meeting plans over the last five years. Transmission additions were higher than average from 2009 to 2010	Industry-wide effort continues in the development of Smart Grid Interoperability Standards

[2] *2009 Long-Term Reliability Assessment:* http://www.nerc.com/files/2009_LTRA.pdf

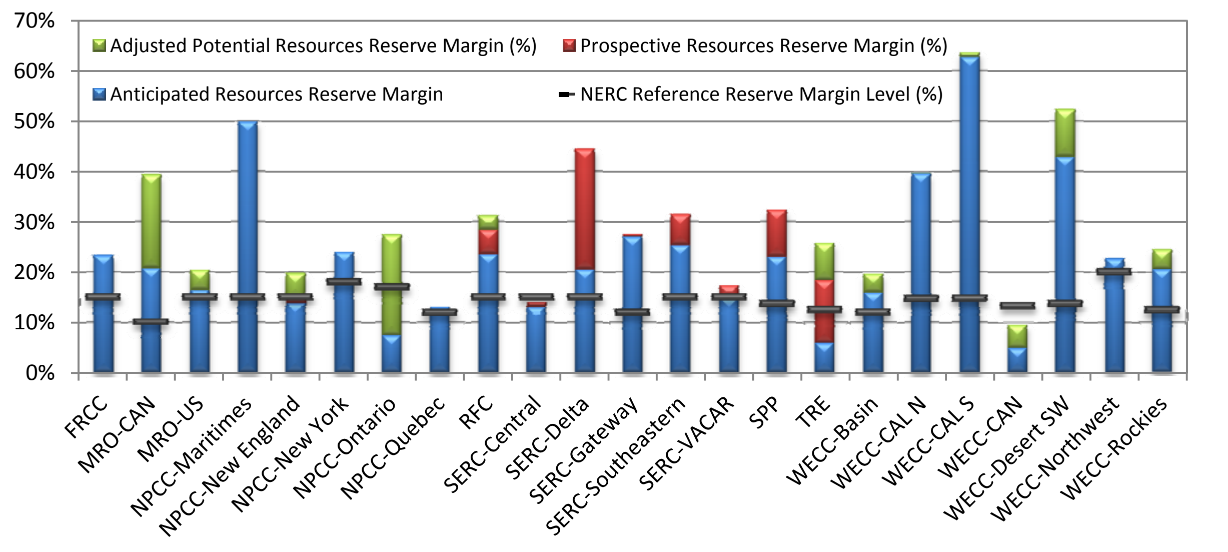
RELIABILITY ASSESSMENT OF NORTH AMERICA

The electric industry has prepared adequate plans for the 2010-2019 period to provide reliable electric service across North America. However, some issues may affect the implementation of these plans. In this section of the report, NERC assesses the future reliability of the bulk power system through many key reliability indicators, such as peak demand and energy forecasts, resource adequacy, transmission development, changes in overall system characteristics and operating behaviors, and other influential policy or regulatory issues that may impact the bulk power system.

PROJECTED PLANNING RESERVE MARGINS

Planning Reserve Margins[3] in many Regions have significantly increased compared to 2009 projections due in large part to the economic recession, which has reduced demand projections. Figure 1 provides the 2019 projected on-peak Planning Reserve Margins in North America (annual peaks) compared to NERC's Reference Margin Level.[4] Overall, NERC Regions and subregions have sufficient plans for capacity to meet customer demand over the next ten years. Additionally, many areas have shown improvement in overall Planning Reserve Margins compared to last year's assessment. In particular, increases are shown in MRO US, NPCC-Quebec, SERC-Southeastern, SERC-VACAR, and WECC-Canada when compared to last year's projections. However, some areas may need more resources by 2019.

Figure 1: 2019 Projected On-Peak Planning Reserve Margins



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[3] Planning Reserve Margins in this report represent margins calculated for planning purposes (Planning Reserve Margins) not operational reserve margins which reflect real-time operating conditions. See *Estimated Demand, Resources, and Reserve Margins* for specific values.

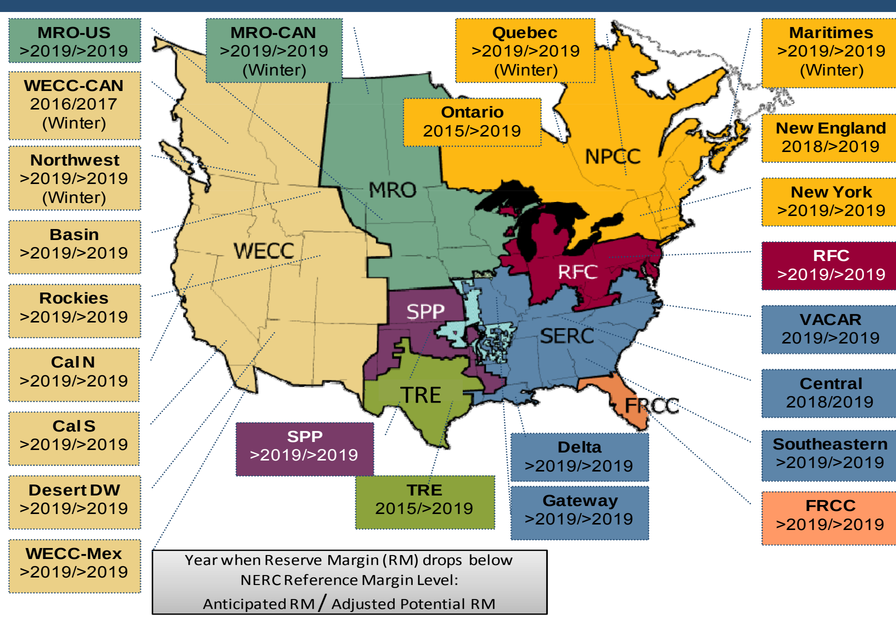
[4] Each Region/subregion may have its own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the Regional/subregional Target Reserve Margin level is adopted as the NERC Reference Margin Level. If not, NERC assigned 15 percent Reserve Margin for predominately thermal systems and 10 percent for predominately hydro systems.

By 2017, WECC-Canada is projected to fall below the NERC Reference Margin Level, when considering Adjusted Potential Resources. Because Adjusted Potential Resources includes Conceptual capacity—adjusted by a confidence factor to account for how much may actually be constructed—resource development in WECC-Canada should accelerate to ensure an adequate Planning Reserve Margin in the long term. SERC-Central is also projected to fall slightly below the NERC Reference Margin Level by 2019. Other tight areas include NPCC-New England, NPCC-Ontario, and TRE, which rely on less certain resource projections (*i.e.,* Prospective and Adjusted Potential Resources) to meet the NERC Reference Margin Level.

The primary driver for the projected increase in Planning Reserve Margin is the overall reduction in projected peak demand throughout the ten-year assessment period.[5] Resource plans must continue as planned in order to maintain the level of reliability projected in this assessment. For example, in NPCC-New England, NPCC-Ontario, SERC-Central, SERC-VACAR, TRE, and WECC-CAN Anticipated Resources (Existing-Certain and Future-Planned Resources) are not sufficient to meet the NERC Reference Margin Level by 2019 (see Figure 2).

In these areas, Adjusted Potential Resources are needed to meet the NERC Reference Margin Level. However, Adjusted Potential Resources carry a higher degree of uncertainty because these resources are in the early stages of development. Therefore, considerable progress must be made in order to bring these resources online in the future. Engineering studies, siting and permitting, and construction represents the activities required before these resources can have reasonable expectation to be in-service. Furthermore, both demand and supply resources (Future resources) are expected to have similar growth over the next ten-years (approximately 100,000 MW). Should demand grow faster than projected, additional Conceptual resources are likely to be available to maintain resource adequacy.

Figure 2: Anticipated and Adjusted Potential Reserve Margins Compared to the NERC Reference Margin Level



[5] A detailed assessment of peak demand projections is found in the *Demand* section.

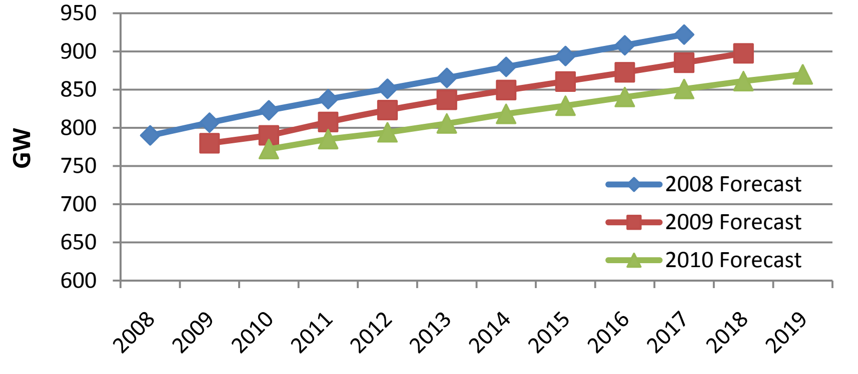
Demand

2010-2019 Demand Forecast

The economic recession is primarily responsible for the significant reduction in projected long-term energy use across North America. For two consecutive years, both peak demand and energy projections have shown significant decreases. While great uncertainty exists in the long-term, effects of the recession are evident in the short-term, affecting electric demand at varying degrees. Demand characteristics of each Region will ultimately determine how the recession has affected demand projections and the extent of the uncertainty in the future.

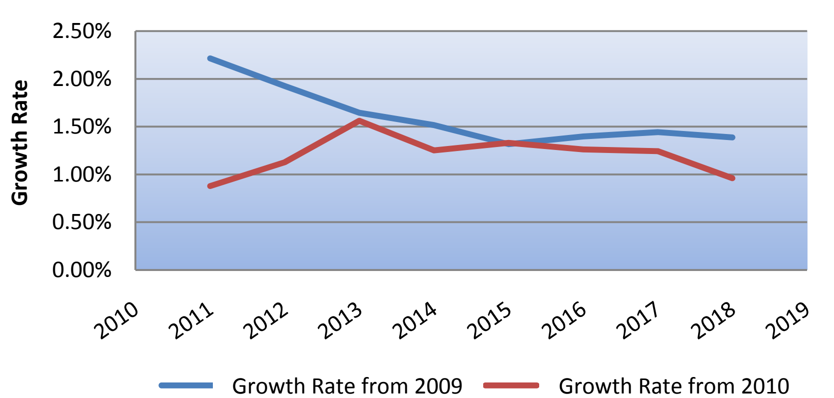
The projections of peak demand and annual Net Energy for Load are aggregates of the Regional forecasts (non-coincident), as of June 2010. These individual forecasts are generally "equal probability" forecast (*i.e.*, there is a 50 percent chance that the forecast will be exceeded and a 50 percent chance that the forecast will not be reached).

Figure 3: Comparison of US Summer Peak Total Internal Demand Forecasts



The 2010-2019 aggregated projections of peak demand for the United States and Canada are lower than those projected last year for the 2009-2018 assessment period. A comparison for 2018, the last common year of the two projections, shows that the summer peak demand for the United States is 36,400 MW lower (or about 4.1 percent lower) than last year's projection. Furthermore, when comparing this year's forecast with the 2008 forecast (pre-recession), the 2017 peak demand forecast is 71,400 MW (or 7.8 percent) less, representing a significant decrease over the past two years (see Figure 3). Overall, recession effects account for a deferment of peak demand approximately four years, where demand previously projected to be realized in 2008 is now not expected to be realized until 2012.

Figure 4: Comparative Annual Growth Rates Total US



Total Internal Peak Demand in the United States is projected to grow at a rate of

1.3 percent per year.[6] While growth rates are projected to be less than last year, some economic recovery effects are evident during the next three years (see Figure 4). Year-on-year growth rates appear to decline in the long term.

Similarly, but not to the same extent, the 2017/2018 winter peak demand for Canada is 600 MW less (or about 0.6 percent lower) than last year's projections for the same year (see Figure 5). However, a larger growth rate of about 1 percent is projected to occur over the next ten years when compared to last year, representing some economic recovery. A slight upward trend in the year-to-year growth rate is projected for the long-term (see Figure 6).

Figure 5: Comparison of Canada Winter Peak Total Internal Demand Forecasts

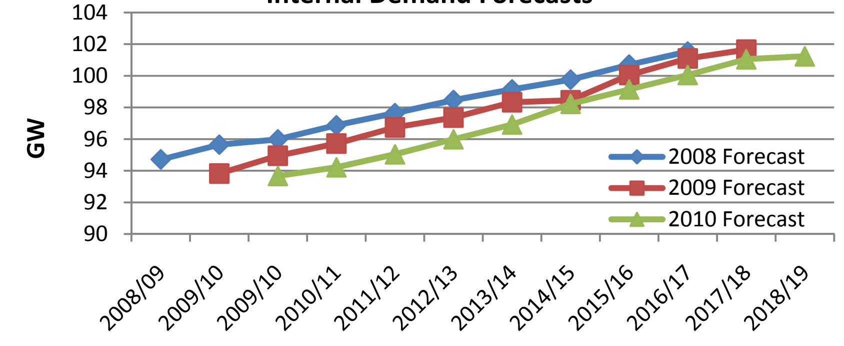
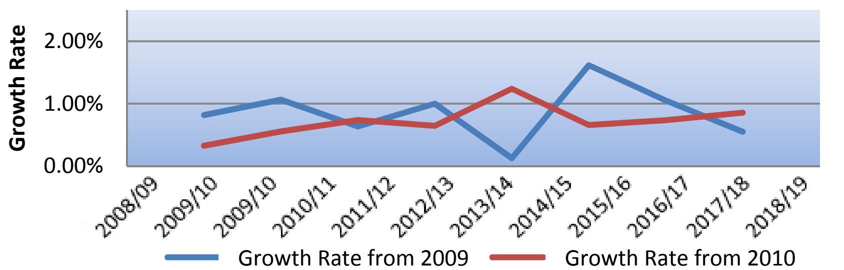


Figure 6: Comparative Annual Growth Rates Total Canada



The growth rates for annual Net Energy for Load are slightly higher than the growth rates for peak demand in both the United States and Canada (see Table 1). This trend indicates an increase in overall load factor, which may put additional stresses, other than meeting peak demand, on the bulk power system. For example, an increase in load factor indicates bulk power system facilities (generators, transmission lines, and transmission equipment) will be used (loaded) at higher levels throughout the year.

Table 1: 2010-2019 Forecast of Peak Demand and Energy

	2010	2019	Growth Rate (%/year) 2010 - 2019
United States			
Summer Peak Demand (GW)	772	870	1.34%
Annual Net Energy For Load (TWh)	3,970	4,613	1.57%
Canada			
Winter Peak Demand (GW)	94	101	0.94%
Annual Net Energy For Load (TWh)	528	597	1.29%

[6] The forecast growth rates are average annual rates calculated for the weather-normalized projections from the first year to the last year of the forecast period. The calculated growth rate uses the log-linear least squares growth rate (LLLSGR) method.

LONG-TERM FORECAST UNCERTAINTY

System planners must consider the uncertainty reflected in peak demand projections in order to maintain sufficient reserve margins in the future. Because electric demand reflects the way in which customers use electricity in their domestic, commercial, and industrial activities, the Regional forecasts are continuously enhanced as the study period approaches. The amount of electricity, which these sectors will demand from the bulk power system in the future depends on a number of interrelated factors:

- Future economic growth
- Price and availability of other energy sources
- Technological changes
- Higher efficiency appliances and equipment
- Customer-driven conservation efforts
- Industrial cogeneration
- Effectiveness of industry-driven conservation and Demand-Side Management programs

Each of these factors has its own set of uncertainties, and their effects on future electricity demand are challenging to predict.

With greater uncertainty in future electricity use attributed to the recent economic recession, continuously updating demand forecasts are essential to the planning process. Furthermore, the pace and shape of the economic recovery will dramatically influence demand growth across North America in the next ten years. Largely unpredictable economic conditions result in a degree of uncertainty in the 2010 demand forecasts that is not typically seen in periods of more stable economic activity. It is vital that the electric industry maintain flexible options for increasing its resource supply in order to respond effectively to rapid, upward changes in forecast electricity requirements and any unforeseen resource development issues.

According to a recent NERC report *2010 Special Reliability Scenario Assessment: Potential Reliability Impacts of Swift Demand Growth after a Long-Term Recession,* a recovery period where economic activity strengthens following a recession has been experienced in the past.[7] Depending on the magnitude and timing of the recovery period, the result of swift demand growth may result in higher than expected demand. Therefore, the complexities of predicting economic factors that will dictate the outcome of the recovery may create forecasting challenges in the near future. While the industry is prepared to handle increased demand growth over a long-term period, rapid demand growth in a short-term can create reliability issues if resources cannot be fully deployed or acquired to meet resource adequacy requirements. The severity of the recent recession, coupled with the uncertainty of the recovery magnitude, renders near-term demand estimates uncertain. Whether changes are cyclical, structural, or both, close monitoring of the recession's influence on electric demand is essential.

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[7] http://www.nerc.com/files/NERC_Swift_Scenario_Aug_2010.pdf

Based on the forecasting bandwidths developed by NERC's Load Forecasting Working Group, the uncertainty of 10.8 percent in the 2010-2019 estimates of annual peak demand growth for the United States and 9.8 percent for Canada is illustrated by a range of projections.[8] For the United States, the bandwidth indicates that there is an estimated 10 percent probability that summer peak demand will increase above 977 GW by 2019 (see Figure 7). This corresponds to a high case growth of 25.4 percent by 2019.

For Canada, the winter peak demand growth by 2019 can increase above 101 GW to 113 GW, with the same probability (10 percent), corresponding to a high case growth of 25.5 percent by the 2019/2020 winter season (see Figure 8).

Figure 7: United States Summer Peak Demand Forecast Uncertainty 2010-2019 Projection and Historical Actuals

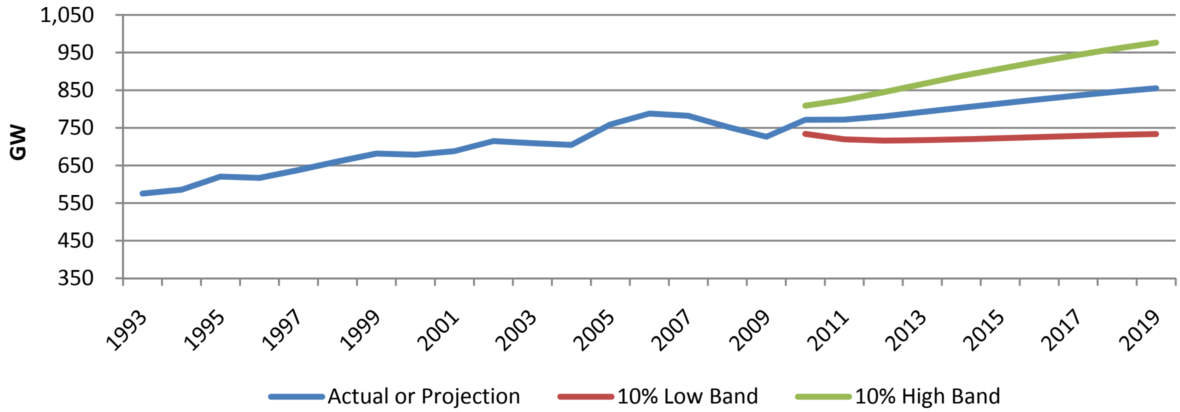
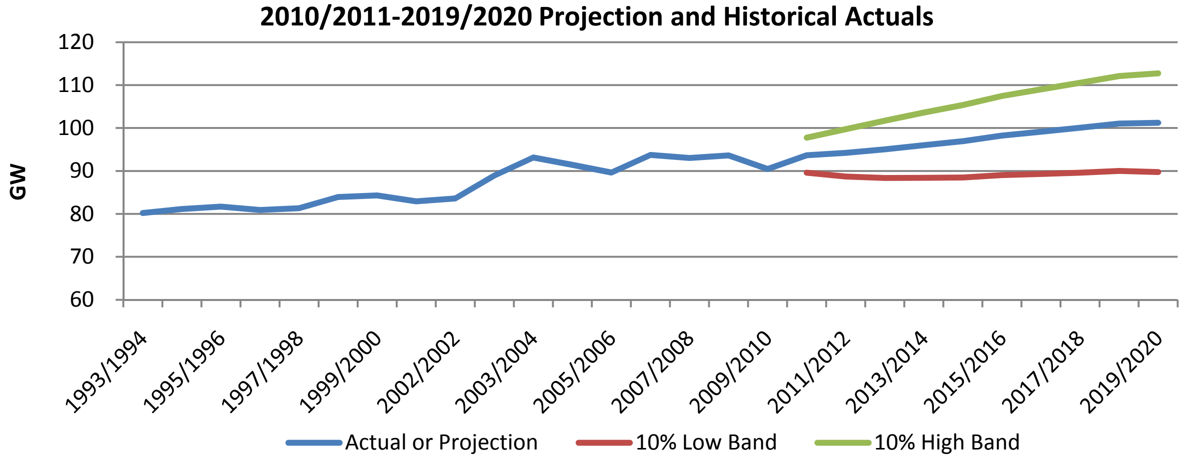


Figure 8: Canada Winter Peak Demand Forecast Uncertainty 2010/2011-2019/2020 Projection and Historical Actuals



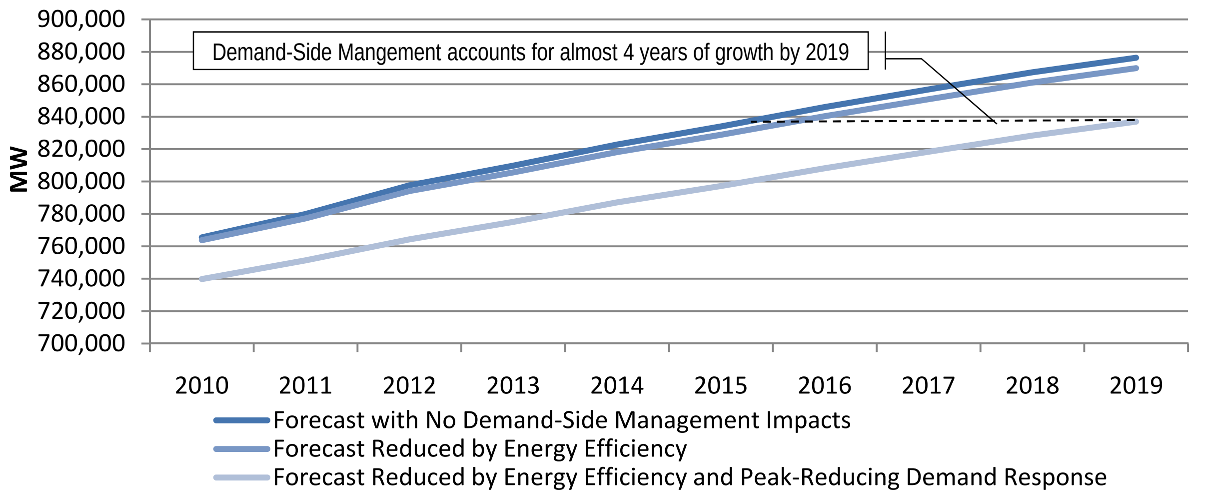
[8] Forecasts cannot precisely predict the future. Instead, many forecasts report a baseline or most likely outcome, and a range of possible outcomes based on probabilities around the baseline or midpoint. Actual demand may deviate from the midpoint projections due to VAriability in key factors that drive electricity use. For these forecasts, 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. The bandwidths produced are theoretical bandwidths based on mathematical representations of the series. They are derived from in sample residuals (fitting errors) and 80 percent standard normal confidence intervals. Bandwidths obtained with the theoretical formulas are then proportionally projected onto the Regional forecasts provided by each Region.

DEMAND-SIDE MANAGEMENT

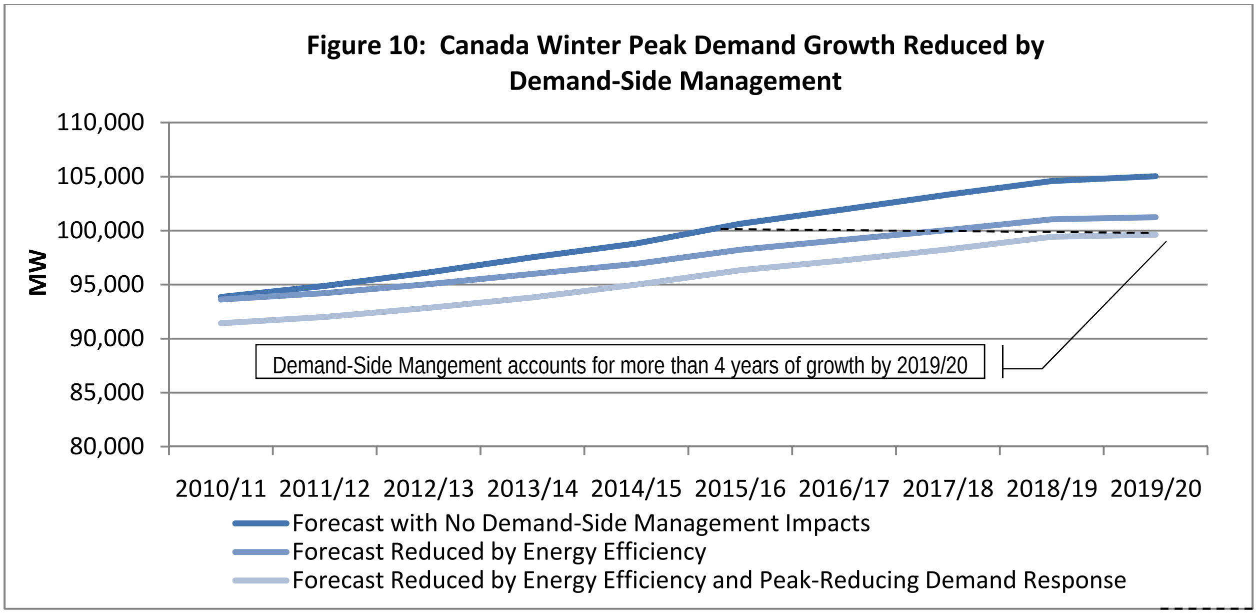
Demand-Side Management programs, which include conservation, Energy Efficiency, and Dispatchable and Controllable Demand Response, provide the industry with the ability to reduce peak demand and to potentially defer the need for some future generation capacity. However, Demand-Side Management is not an unlimited resource and may provide limited demand reductions during pre-specified time periods. Some Regions have been heavily involved in Demand-Side Management for many years, such as FRCC, NPCC, TRE and WECC, while others have less penetration. Historical performance data from these Regions may also provide a way to analyze the benefits from these resources.[9] The structure of Demand-Side Management programs (*e.g.*, performance requirements, measurement and verification applicability, resource criteria) may be indicative of how well these programs perform when needed. Therefore, the shared experiences and lessons learned from these high-penetrated areas should benefit the North American bulk power system in providing more planning and operating flexibility.

All Regions are projecting at least some increased use of Demand-Side Management over the next ten years to reduce peak demands, contributing either to the deferral of new generating capacity or improving operator flexibility in the day-ahead or real-time time periods. In the U.S., Demand-Side Management is projected to account for roughly 40,000 MW (or about 4 percent of the peaking resource portfolio), effectively offsetting peak demand growth by nearly four years (see Figure 9). In Canada, about 5,500 MW are reduced, resulting in the offsetting of peak demand growth by just over four years (see Figure 10). Ontario, in particular, has set aggressive Energy Efficiency targets, resulting in a projected 3,500 MW reduction in peak demand.

Figure 9: 2010-2019 US Summer Peak Demand Growth Reduced by Demand-Side Management



[9] NERC DADS is collecting Demand Response data on a semi-annual basis. The goal of the DADS is to collect Demand Response enrollment and event information to measure its actual performance including its contribution to improved reliability. Ultimately, this analysis can provide industry with a basis for projecting contributions of dispatchable and non-dispatchable (*e.g.*, price-driven) Demand Response supporting forecast adequacy and operational reliability. http://www.nerc.com/page.php?cid=4|357



Through Energy Efficiency and Conservation, permanent replacement and/or more efficient operation of electrical devices results in demand reductions across all hours of use, rather than event-driven targeted demand reductions. In the next ten-years, Energy Efficiency across all NERC Regions is expected to reduce demand by approximately 10,300 MW on peak. While most Regions/subregions show increases when compared to last year, some decrease in Energy Efficiency is projected in SERC and WECC. As a result of implementing Energy Efficiency programs, the electric industry in North America has effectively deferred the need for new generating capacity by approximately one year. The ability to implement Energy Efficiency programs in a relatively short time period provides the industry with another short-term solution to defer any anticipated capacity short-falls. Successful integration of Energy Efficiency into resource planning requires close coordination between those responsible for Energy Efficiency and those in bulk system planning to ensure appropriate capacity values are estimated while meeting reliability objectives.

The type of Energy Efficiency programs (industrial, commercial, and residential) influence the total capacity (MW) reduction depending on the time of day and the reduction that is desired. Load forecasting is a critical component to understanding the overall peak reduction observed or projected. Tracking and validating Energy Efficiency programs is vital to increase the accuracy of forecasts. In some areas, experience with these demand-side resources has improved. For example in ISO-NE, demand-side resources can participate just like traditional generation resources in the Forward Capacity Market.[10] The ability to demonstrate effective performance of these, illustrates the confidence exhibited by system planners and operators in using demand-side resources to fulfill capacity obligations and maintain the same level of reliability.

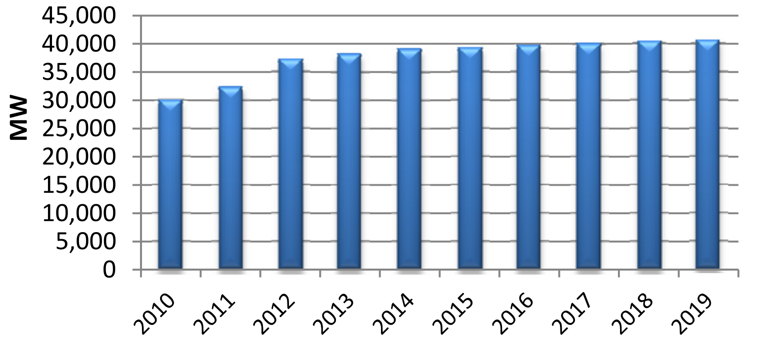
Potential drivers for the continued expansion of Energy Efficiency programs in the future are Renewable Portfolio Standards (RPS), which commonly include provisions for energy-reducing actions to account for

[10] http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/cap_mkt/index.html

a portion of the renewable resource requirement (generally no more than 5 percent of total energy use). Other policy drivers include the American Recovery and Reinvestment Act of 2009[11], which includes provisions for significant investments in energy and climate related initiatives; the proposed American Clean Energy and Security Bill of 2009[12], which established credits for reduced carbon emissions; the Climate Change Plan for Canada[13]; and several Regional, state, and provincial initiatives.[14]

In terms of Demand Response (Dispatchable and Controllable), expected contributions slightly decreased from 32,200 MW for 2009 to 30,000 MW for 2010. Growth exists within the short-term projections approximately 3 years out, but plateaus in the long-term to just over 40,000 MW (see Figure 11). The plateau effect represents the uncertainty in committing Demand Response beyond what is currently planned and contracted.

Figure 11: Total Dispatchable and Controllable Demand Response On-Peak Projections



As highlighted later in this report, uncertainty exists not only in how much peak demand reduction will actually be realized at the particular time when Demand Response is needed and deployed, but also in the long-term sustainability of these resources.[15] Unlike traditional generating resources with many decades of historic data for analysis, the long-term projections of Demand Response involve greater forecasting uncertainty. Because participation in Demand Response programs is highly dependent on a number of economic variables and incentives, it is challenging to forecast how much Demand Response will be available in 2019.[16]

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[11] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h1enr.txt.pdf

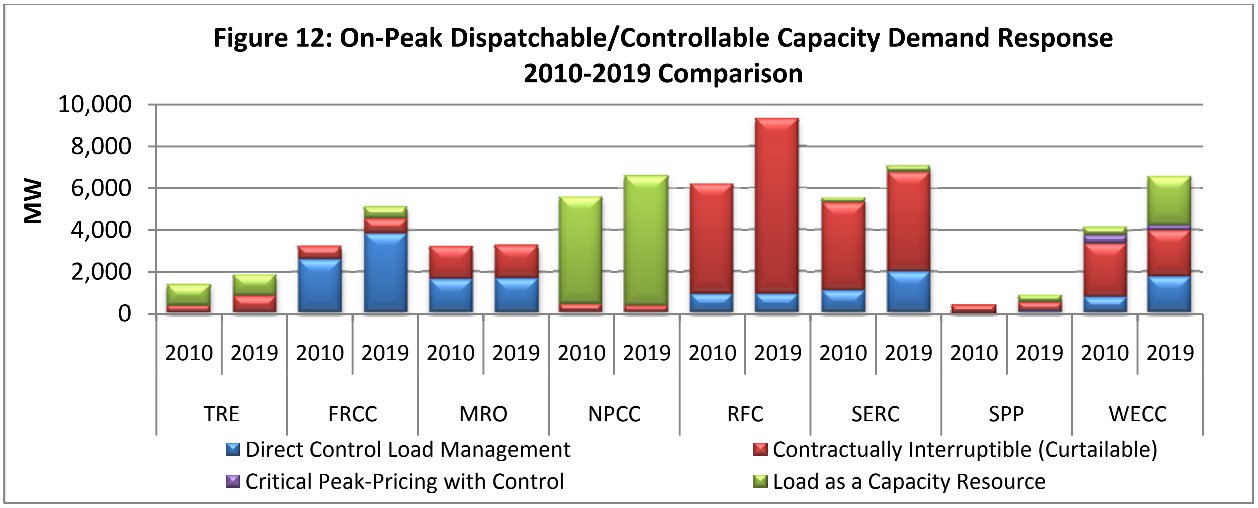
[12] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h2454pcs.txt.pdf

[13] http://dsp-psd.pwgsc.gc.ca/Collection/En56-183-2002E.pdf

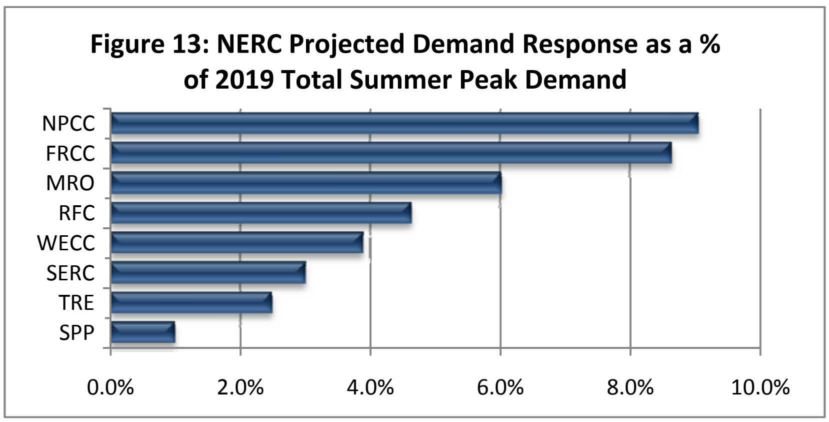
[14] Reliability Impacts of Climate Change Initiatives report: http://www.nerc.com/files/RICCI_2010.pdf

[15] Refer to the *2010 Emerging Reliability Issues: Uncertainty of Sustained Participation in Demand Response Programs* section

[16] In most cases, actual forecasting of Demand Response is not performed. Rather projections are based on resource requirements and the amount of capacity contracted during a given commitment period--usually between one to three years.



As previously stated, much of the increase is in the short-term. Within the short-term, significant growth is projected in FRCC, RFC, SERC, and, WECC (see Figure 12). Participation in Demand Response programs continue to grow, not only in magnitude, but also as a percentage of Total Internal Demand. NPCC, FRCC, and MRO all maintain demand resources greater than five percent of their projected peak demand (see Figure 13)



Demand Response also plays an important role in managing system balancing on a daily and real-time basis, which is discussed in the *Operational Issues* section of this report.

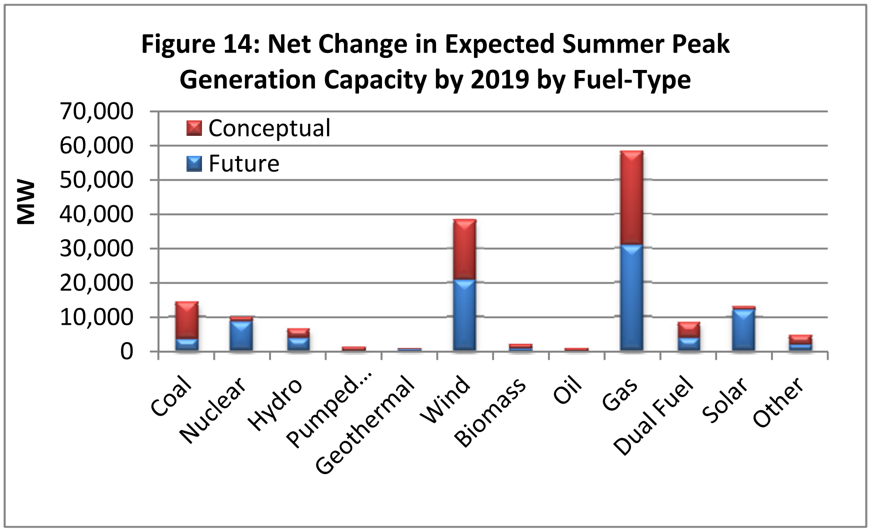
GENERATION

2010-2019 GENERATION PROJECTIONS

The total Existing-Certain capacity increased NERC-wide by 11,200 MW (or 1.1 percent) when compared to last year. Within the next ten years, approximately 131,000 MW of new generation resources are Planned, with the largest fuel-type growth in gas-fired and wind generation resources (see Figure 14)—an additional 244,000 MW are Conceptual.[17] Of the 131,000 MW of Planned capacity, approximately 85,000 MW are expected to be available on peak by 2019.

[17] Variable resource capacity values represent the nameplate/installed generation rating. On peak, the capacity values are between roughly 8 to 30 percent.

Despite the recent economic recession and lower demand forecast, generation resources continue to be interconnected to the bulk power system—albeit at a lower than expected rate when compared to the 2008 pre-recession forecast. Since last year, approximately 11,000 MW of gas-fired generation and 8,900 MW of installed (nameplate) wind generation was added across North America representing the largest fuel-type increases in generation.[18]



In some Regions, resource plans and market conditions have reacted to the reduced long-term peak demand and energy projections. For example, in the TRE Region, the mothballing of four (4) plants by the end of this year reduces gas-fired generation by about 2,500 MW. However, by 2014, approximately 3,100 MW of new resources (primarily coal- and gas-fired generation) will be added in the TRE Region.

VARIABLE GENERATION

Variable resources are growing in importance in many areas of North America as new facilities come online. With growing dependence on wind and solar generation, it is vital to ensure that these variable resources are reliably integrated into the bulk power system addressing both planning and operational challenges.[19]

Table 2: Wind and Solar Nameplate Capacity - Existing and 2019 Projections

	Wind			Solar		
	2010	2019 Planned	2019 Conceptual	2010	2019 Planned	2019 Conceptual
FRCC	0	0	0	33	20	0
MRO	7,540	1,770	41,010	0	0	0
NPCC	3,631	2,228	12,355	1	0	162
RFC	4,093	16,687	19,016	0	6	567
SERC	102	68	1,199	0	0	5
SPP	2,699	796	19,232	16	0	41
TRE	9,116	1,326	30,093	0	0	549
WECC	9,635	18,192	1,610	534	12,367	0
Total	**36,816**	**41,067**	**124,515**	**584**	**12,393**	**1,324**

While the addition of large amounts of variable resources (predominantly wind and solar) to the bulk power system will change the mix of installed (nameplate) capacity in the coming decade,

[18] This sum of these two values are greater than the amount of Existing-Certain capacity because the wind value is not derated and some new gas-fired generation is not considered Existing-Certain. Gas-fired generation is the largest single-fuel increase in terms of expected on-peak capacity.

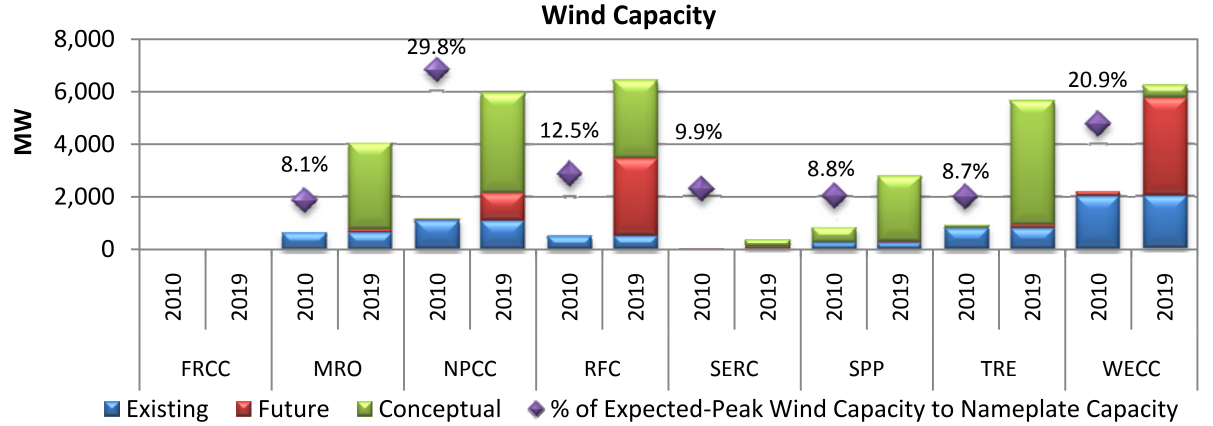
[19] Accommodating High Levels of Variable Generation: Summary Report: http://www.nerc.com/files/Special%20Report%20%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf

the mix of supply resources expected to serve peak demand will remain largely about the same as today. Approximately 180,000 MW of wind and solar resources are projected to be added to the bulk power system by 2019, of which 53,000 MW are Planned and 126,000 MW are Conceptual (see Table 2).[20] Wind and solar resources account for 95 percent of the renewable resource additions and represent 60 percent of all projected resources by 2019. MRO, RFC, SPP, TRE, and WECC all project large wind additions and WECC projects over 12,000 MW of Planned solar additions.

The amounts of wind expected on peak are projected to rise from 5,200 MW (36,816 MW nameplate) to 13,300 MW (41,067 MW Planned-nameplate) for wind (see Figure 15). When considering Conceptual wind resources, expected on-peak capacity can increase to approximately 24,000 MW (124,515 MW Conceptual-nameplate). Availability of capacity during times of peak demand (expected on-peak capacity) is an important issue facing wind power when discussing reliability. Because both the availability of variable generation resources sources and demand for electricity are often weather dependent, there can be consistent correlations between system demand levels and variable generation output. For example, in some cases, due to diurnal heating and cooling patterns, wind generation output tends to peak during daily off-peak periods. Also, many areas have experienced wind generation output falling off significantly during summer or winter high-pressure weather patterns that can correspond to system peak demand.[21] Therefore, the methods for determining available wind capacity during peak hours becomes increasingly important as more wind resources are interconnected to the bulk power system.[22] On average, the expected on-peak capacity for wind generation in North America is approximately 14.1 percent of nameplate capacity.

Current expected on-peak capacity values range from 8.1 percent to nearly 30 percent. While solar has some availability issues (*i.e.*, diversity, dispersion of cloud cover), the derate associated with on-peak capacity is not as large (approximately 75 percent of nameplate solar capacity is expected on peak).

Figure 15: Projected Increase in Existing, Future & Conceptual Summer On-Peak Wind Capacity



[20] Refer to the *Terms Used in This Report* Section for detailed definitions of these supply categories.

[21] EoN Netz Wind Report 2005

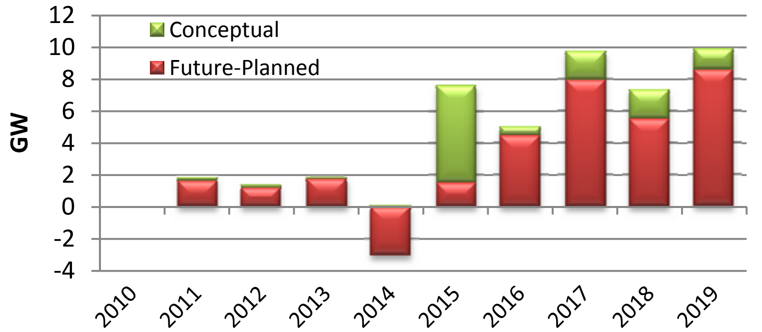
[22] Regional differences exist for calculating the expected on-peak capacity contributions of wind resources. http://www.nerc.com/docs/pc/ivgtf/IVGTF_Report_041609.pdf

Significant development of wind resources is expected in RFC and WECC. Much of the projected resources are considered Planned and represent a higher certainty that those resources will be constructed. In the SERC-Gateway subregion, development of new wind resources is planned to increase to over 800 MW by 2018. Wind resources are not expected in FRCC.

Even with the amount of new variable resources being integrated into the bulk power system, of the total supply in 2019, fossil-fired, nuclear, and hydro generation is projected to provide over 90 percent of the capacity necessary to meet peak demand in North America by 2019.

While gas-fired generation resources are projected to remain the largest fuel source used to meet demand on peak, a significant amount of new nuclear resources are also projected. The design specifications for these new nuclear units are large (over 1,600 MW) when compared to a single new gas-fired turbine unit (approximately 600 MW). The inclusion of new nuclear units into the bulk power system may require significant transmission upgrades to support the new generation and the ability to deliver the large amounts of power. Because of the long-lead times for major transmission development and siting, and the long lead-time for new nuclear units, transmission development may be needed sufficiently far in advance to ensure that the transmission system will be ready to accommodate these units when they are licensed for operation.

Figure 16: Projections of Net Change to Existing, Future, and Conceptual Nuclear Capacity: 2010-2019



Six new nuclear units are being added at existing sites in SERC providing the Region with an additional 1,600 MW of capacity in 2013 and 9,000 MW by 2019. Additional Conceptual up-ratings of approximately 1,300 MW are also expected within the ten year assessment time frame. Altogether, the increase of nuclear capacity represents a 10 percent increase compared to existing capacity. In RFC, 15 nuclear plants are projected to be refurbished or brought back into service over the next 10 years; increasing the nuclear capacity by approximately 6,000 MW (half of these additions are categorized as Conceptual resources). Two nuclear plants, totaling almost 6,000 MW of new capacity, are also classified as Conceptual in TRE. In Ontario, the restart of two units at Bruce Nuclear Station A, about 1,500 MW, could be offset by a 3,000MW reduction if the Pickering Nuclear Generating Station is retired when the units reach end of normal life in 2014 and 2015. Overall, nuclear plant capacity is projected to have a net increase of approximately 10,000 MW by 2019 (see Figure 16).

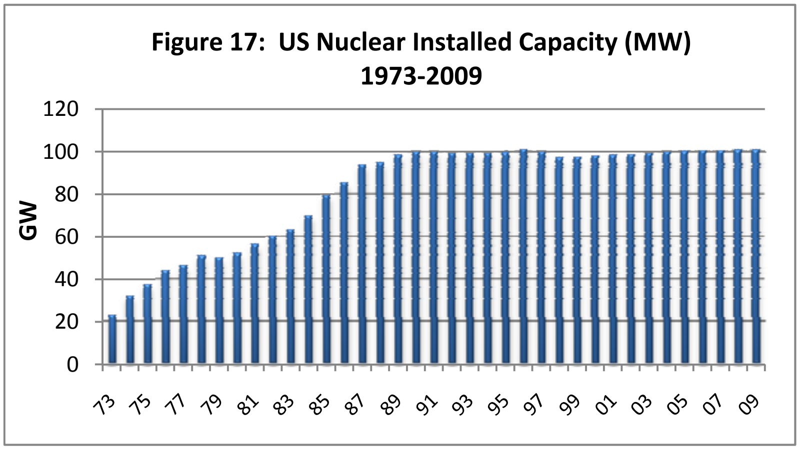


Figure 17: US Nuclear Installed Capacity (MW) 1973-2009

The almost 10 percent increase in new nuclear capacity is the largest ten year increase since the early-1980's (see Figure 17), presenting some challenges that must be considered. While nuclear generation provides a source of constant, base-load generation, large, inflexible generation units limit the ability of operators to dispatch resources and may also increase contingency reserve requirements. That said, with roughly 50 years of industry experience in operating nuclear generation, operating practices and procedures have increased the effective reliability of these resources. Additionally, nuclear generation is capable of producing large amounts of energy with little or no carbon emissions and can supply the industry with the needed capacity should greenhouse gas legislation and/or environmental regulations come to fruition.[23]

Projected Generation Uncertainty

All future plans are subject to uncertainty, and plans for generation capacity are no exception. As observed today, the recent economic recession has reduced long-term projections in peak demand and energy. In addition, new generation is subject to delays due to licensing, regulation, financing and public intervention, as well as to the complexities in constructing large projects.

Natural gas has become the predominant option 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 when compared to coal and oil generation facilities. Certain states have placed or plan to place a moratorium on building new coal plants, citing environmental and emissions concerns as justification. [24] These 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[25]

The continued operation of existing generation capacity must also be considered over the next ten years, particularly in regards to proposed United States Environmental Protection Agency (EPA) regulations that have the potential to affect fossil-fired generation capacity across the United States.[26]

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[23] Solomon, S. et al. (eds.) *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* (Cambridge University Press, Cambridge and New York, 2007); http://www.ipcc.ch/pdf/assessment-report/ar4/wg1/ar4-wg1-spm.pdf

[24] California's SB 1368 created the first de facto governmental moratorium on new coal plants in the United States. Other states with pending proposals include Arkansas, Georgia, Idaho, Maine, New Jersey, Texas, Utah, Washington, and Wisconsin—though some are temporary. Additionally, Ontario and British Columbia have also begun initiatives to not only halt new coal-fired generation, but also reduce coal-fired generation.

[25] A detailed fuel assessment in the 2009 Long-Term Reliability Assessment: http://www.nerc.com/files/2009_LTRA.pdf

[26] *2010 Special Reliability Assessment Scenario: Resource Adequacy Impacts of Potential U.S. Environmental Regulations:* *http://www.nerc.com/files/EPA_Scenario_Final.pdf*

Several regulations are being promolgated by the EPA. Depending on the outcome of any or all of these regulations, the results may accerlerate the retirement of some fossil fuel-fired power plants. The EPA is currently developing rules under their existing regulatory authority that would mandate existing power suppliers to invest in retrofitted environmental controls at existing generating plants or retire them. In particular, four active EPA rulemaking proceedings could have significant effects on grid reliability as early as 2015. These rules under development include:

1. Clean Water Act – Section 316(b), Cooling Water Intake Structures
2. Coal Combustion Residuals (CCR) Disposal Regulations
3. Clear Air Transport Rule (CATR)
4. Title III of the Clean Air Act – National Emission Standards for Hazardous Air Pollutants (NESHAP) for the electric power industry or (Maximum Achievable Control Technology (MACT) Standard)

As a result of these accelerated retirements, capacity reductions may diminish reserve margins and could impact bulk power system reliability in the near future.

Potential impacts of EPA regulations on bulk power system reliability include not only retrofitting existing generation but also constructing or acquiring replacement generation or other resources. Bulk power system planning and operation approaches, processes, and tools will require sufficient time for changes to be made, otherwise either reliability will suffer or aggressive environmental goals may not be attainable. Therefore, the risk to reliability is a function of the compliance timeline associated with the potential EPA regulations.

In Canada, greenhouse gas reduction initiatives, such as Ontario's Green Energy Act, are driving down carbon emissions through stringent, fast-paced legislation.[27] Ontario is expected to retire up to 9,000 MW (coal and nuclear) over the next ten years due to both strict emission standards and lack of economic drivers to warrant refurbishing units reaching end of life.

Generation Fuels Assessment

An adequate supply of fuel for existing and planned generating capacity is fundamental to the reliability of the bulk power system. Overall, based on the projected generation resources included in this assessment, a sufficient inventory of fuel is expected over the next ten years. While some concerns exist in a high-penetration of gas scenario, in terms of meeting the gas demands and constructing the infrastructure needed for delivery (availability, deliverability, and transportation), a massive evolution from coal to gas-fired generation is not in the current plan. In contrast, the domestic supply of coal appears to be adequate though tighter coal stock piles have been recently observed due to the post-economic recession effects.

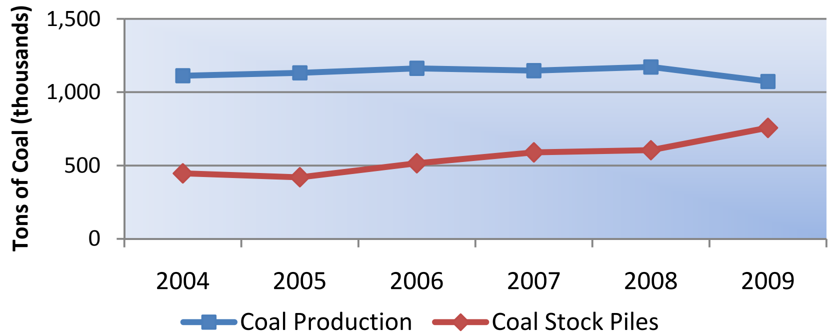
Coal Assessment

The drop in coal demand led to sharp increases in customer stockpiles as generators continued to take delivery of coal contracted when demand expectations were higher. Stockpiles grew last year to levels not seen in the industry before, over 757 million tons (see Figure 18). In 2009 and 2010, generators cut

[27] http://www.mei.gov.on.ca/en/energy/gea/

back deliveries to match the lower burn and are likely to cut deliveries of coal further to bring existing inventories back to historical levels. The reduced purchases by generators have forced mine closures, especially in Appalachia, where the cost of coal production is higher than the rest of the industry.

Figure 18: Total Coal Production vs. Coal Stockpiles in Electric Power by Year End Data



There is a significant possibility that coal-fired generation will rebound when the recession ends and economic growth in the United States recovers. This will bring both increased demand for electricity and increased demand for natural gas in the industrial sector, both of which would stimulate a return of coal-fired generation to previous levels. A rapid recovery of coal-fired generation could lead to a supply shortage in this time frame, as production will be slower to recover, especially in Appalachia, where the barriers to entry have continued to grow.[28]

Historically, coal has been the fossil-fuel with the highest reliability of supply and the most stable price for generating electricity. However, there is reason for the electric power industry to be more concerned in the short-term about the reliability of coal supply. Short-term disruptions in 2004 and 2008, accompanied by ever-greater price shocks, are a clear indication that the U.S. coal industry no longer has the excess production capacity to respond to extreme surges in demand. Other sectors of the coal supply chain have sought to minimize excess capacity as well, as customers have reduced coal stockpile levels and transportation companies have eliminated excess capacity. Further, productivity in coal production has declined steadily since its peak in 2000, as mining conditions have become more difficult and mining regulations more restrictive.

Gas Assessment

A shift to unconventional gas production in North America has the potential to increase availability of gas supply in the future. 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.

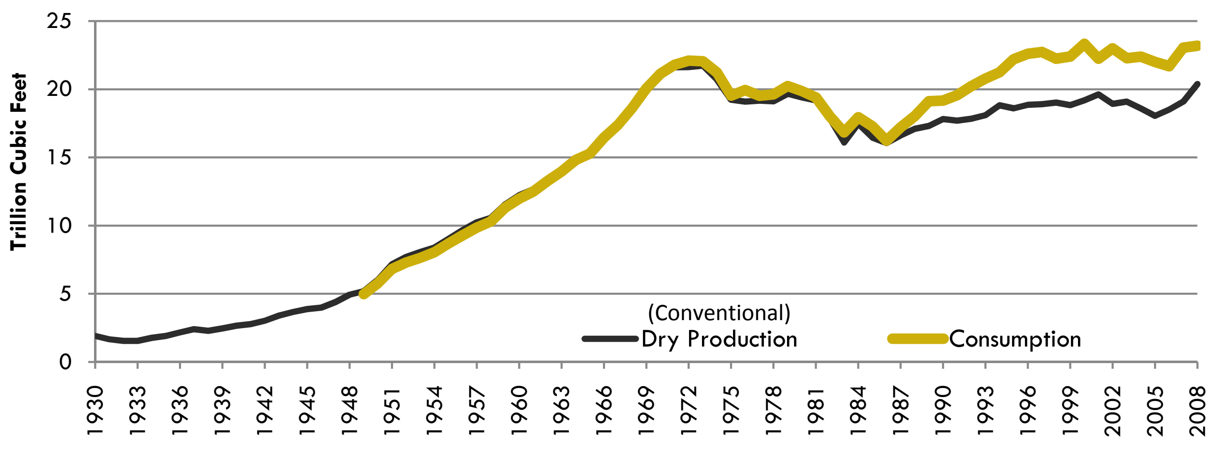
The precise annual growth rates of gas production from the newer unconventional basins (*e.g.*, shale gas), which are still in their infancy, are uncertain given the large amount of new drilling that is required to extract the gas. Successful development of unconventional gas is dependent on advanced technology that requires horizontal drilling of well bores, hydraulic fracturing of the rock with large amounts of

[28] It is more difficult to obtain a mining permit than before and the mining is more labor-intensive, which could lead to labor shortages if demand rebounds.

high-pressure water, and real-time seismic feedback to adjust the stimulation method. Issues that may adversely affect future production from unconventional resources include access to, and drilling permits for, land that holds the resources, availability of water for drilling, wastewater disposal, and unfavorable state or provincial tax regimes or royalty structures. While these environmental issues have the potential to threaten long-term gas production, the industry will continue to work to address these concerns in the future.[29] Accompanying the shift to unconventional basins, recent large-scale expansions of U.S. gas transportation, delivery and storage infrastructure significantly alleviate short-term supply dislocations from potential events such as pipeline outages, production outages or hurricanes.

Natural gas-fired on-peak capacity is projected to exceed coal-fired on-peak capacity by 2011. Among the primary drivers are that natural gas generation plants are generally easier and faster to site, and have lower capital costs than other alternatives. If some form of carbon tax or cap-and-trade is implemented, natural gas will become a more desirable fossil-fuel because its combustion results in almost 50 percent less carbon dioxide than coal per MW generated. Coupled with higher availability of unconventional natural gas supplies (*e.g.*, gas in shale formations, which represent up to two-thirds of North America's potentially recoverable gas reserves[30],[31]), developers could substantially increase gas-fired plant additions, changing the North American fuel mix while increasing the dependency on a single, largely domestic fuel type. Natural gas consumption is at all-time highest levels and expected to increase over the next ten years (see Figure 19a).

Figure 19a: Annual Natural Gas Demand and Supply since 1930



Access to new conventional and unconventional natural gas supplies in North America, coupled with the need to meet the goals of climate change initiatives as well as proposed EPA regulations, is projected to

[29] http://www.prlog.org/10932237-environmental-and-public-health-concerns-might-hamper-shale-gas-production-in-the-us-published.pdf

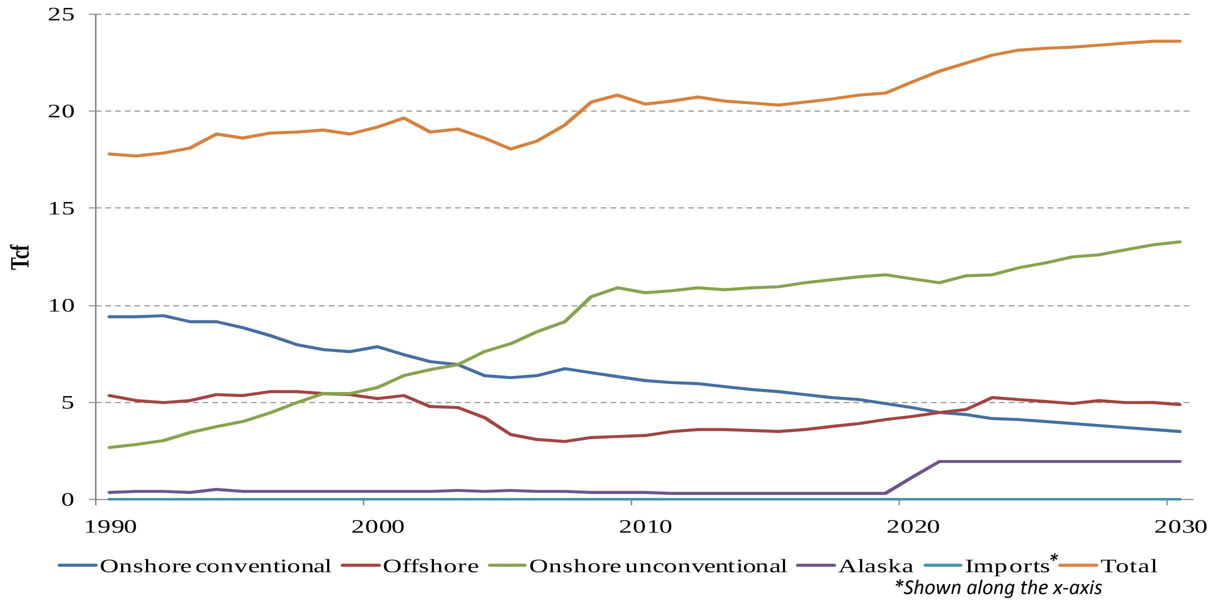
[30] *2010 Annual Energy Outlook: Natural Gas Demand* http://www.eia.doe.gov/oiaf/aeo/gas.html

[31] *The Economist*, August 15–21, 2009, Pg. 24, "The Economics of Natural Gas: Drowning in it"

drive the transition from coal to gas plants beginning within the next ten years. Sufficient time will be required to site new gas-fired generation and construct the needed infrastructure for gas delivery and transport. Continued coordination between the electric power industry and the gas pipeline industry will be critical in meeting the potentially increasing demands from gas-fired generation.

Natural gas production and imports in the United States from 1990 to 2030—both historical and forecast—are shown in Figure 19b. Higher estimates of available North American natural gas come from access to unconventional sources[32] such as shale formations. These sources were formerly difficult and expensive to reach.

Figure 19b: Natural Gas Production and Imports in the United States



Long-term planning of natural gas resources is based on firm contracts for fuel transportation, where 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 may hamper the development of necessary supply and delivery infrastructure such as pipelines.

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, are being 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.

[32] Unconventional Gas refers to gas not found in conventional types of formations. Tremendous advances in drilling techniques use multiple fractures in a single horizontal well bore with real-time micro-seismic technology to monitor fractures. This approach can unlock gas from tight sands, coal-bed methane, and shale.

NUCLEAR ASSESSMENT

There is limited capacity in North American nuclear fuel cycle processes given almost 25 years of underinvestment due to the highly sensitive nature of the technologies, the large capital costs, the large-scale of the required industrial operations, and safety concerns. Enrichment is perhaps the most constrained aspect of the fuel cycle; however, impacts due to the reliability of the nuclear fuel supply have not yet emerged in North America nor are they expected within the next ten years. North American dependence on imported supplies of enriched uranium may leave it vulnerable to long-term supply disruptions, particularly as global demand for enriched uranium accelerates with the construction of new plants outside of North America. However, uranium extraction and enrichment is not expected to cause any reliability concerns within the next ten years.

TRANSMISSION

TRANSMISSION RELIABILITY ASSESSMENT

The existing electric transmission systems and planned additions over the next ten years appear generally adequate to reliably meet customer electricity requirements. However, reliability concerns exist in some Regions where transmission facilities have not been allowed to be constructed as planned. While deferments of projects do not necessarily pose risks to reliability, resulting from lower projected demand due to the economic recession, delays in transmission construction due to permitting and siting have been observed and continue to inhibit the ability for the industry to effectively construct new, and potentially vital transmission. The future reliability of the bulk power system is largely dependent on the ability to site and permit new transmission facilities in a timely manner. The importance of more transmission is magnified when considering the addition of large amounts of variable generation resources, pending greenhouse gas legislation, and increased demand over the next ten years. As recognized in the *2009 Long-Term Reliability Assessment,* transmission permitting and siting is considered one of the highest risks facing the electric industry over the next ten years. It is important that that Local, State, and Federal regulators develop an effective and timely solution to resolve the siting and permitting issues that surround vital transmission projects in the United States.

The electric industry continually assesses the ability of their internal transmission systems and interconnections with other systems to meet their Regional requirements and NERC Reliability Standards. In these assessments, short and long-term needs are identified. Once identified, a transmission project can take, on average, up to ten years to complete from project identification to final electrification. A majority of this time is devoted to the siting and permitting process, which has no definitive timeframe and can vary greatly depending on the location of where the additions have been proposed.

PLANNED TRANSMISSION ADDITIONS

Transmission circuit line mile additions projected for the future are an indicator of the relative strengthening of the transmission system. Significant transmission projects are being planned for the next ten years across North America. The projected additions in transmission circuit miles by voltage class are shown in Table 3.[33] Although the addition of transmission circuit miles indicated positive reinforcement of the interconnected systems, the associated increased use of transmission systems due to increased demand growth, generation additions (especially geographically distant generation), generation deficiencies, and the increasingly competitive bulk power market must also be considered in evaluating overall system strength and reliability.

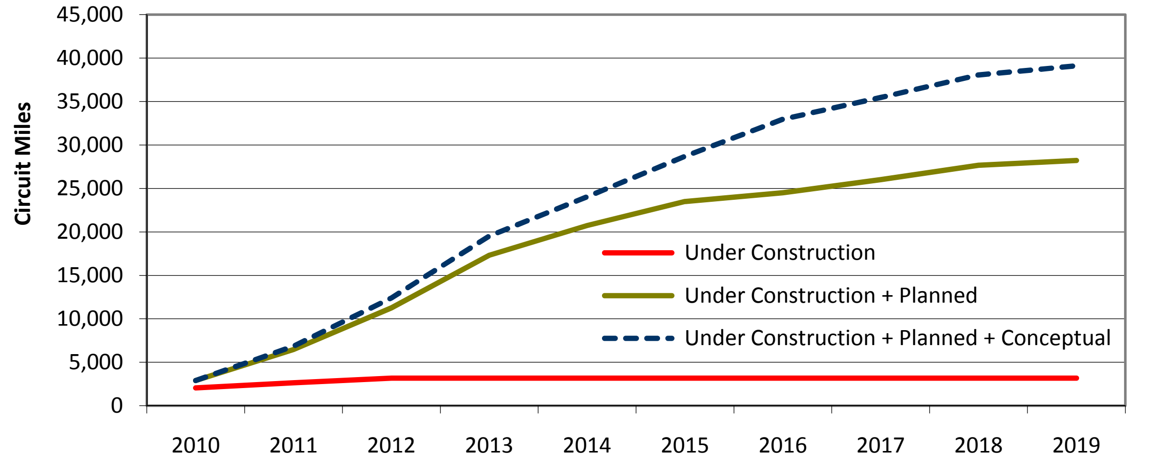
Table 3: Transmission Plans by Circuit Mile Additions > 100 kV

		2008 Existing	2009 Existing	Under Construction	2010-2014 Planned Additions	2010-2014 Conceptual Additions	2015-2019 Planned Additions	2015-2019 Conceptual Additions	Total by 2019
United States									
FRCC	-	7,319	12,016	21	129	-	227	-	12,393
MRO	-	36,482	37,575	207	772	239	663	825	40,281
NPCC	-	13,638	13,647	192	523	-	7	16	14,385
	New England	2,770	2,794	74	523	-	7	16	3,414
	New York	10,868	10,853	117	-	-	-	-	10,971
RFC	-	60,074	60,088	104	1,559	-	168	-	61,919
SERC	-	97,256	98,296	793	1,534	155	1,055	1,476	103,309
	Central	18,114	18,220	161	109	9	-	-	18,499
	Delta	16,431	16,355	285	580	10	109	-	17,339
	Gateway	7,751	7,793	26	225	-	223	909	9,176
	Southeastern	27,234	27,402	42	232	136	200	497	28,509
	VACAR	27,726	28,526	279	388	-	523	70	29,786
SPP	-	23,593	23,814	235	1,920	48	293	270	26,580
TRE		28,665	28,665	58	4,657	-	375	-	33,755
WECC	-	98,030	98,239	1,093	4,383	1,949	3,436	5,014	114,114
	Basin	N/A	12,763	189	1,508	280	2,291	1,503	18,534
	Cal-N	N/A	15,531	196	373	350	-	2,788	19,238
	Cal-S	N/A	12,057	224	410	492	-	415	13,598
	Desert SW	15,562	15,049	26	1,129	807	127	253	17,391
	NWPP	43,255	30,431	220	194	20	810	10	31,685
	RMPA	12,209	12,408	238	769	-	208	45	13,668
Total-U.S.		365,058	372,340	2,702	15,477	2,391	6,224	7,601	406,736
Canada									
MRO	-	12,188	12,188	100	516	363	1,009	80	14,255
NPCC	-	45,300	45,647	322	218	614	-	398	47,198
	Maritimes	4,992	5,019	-	-	-	-	103	5,122
	Ontario	17,624	17,698	108	218	125	-	-	18,149
	Quebec	22,685	22,930	214	-	489	-	295	23,927
WECC	-	21,189	21,122	162	658	-	323		22,265
Total-Canada		78,677	78,957	584	1,392	977	1,332	478	83,719
Mexico									
WECC	CA-MX Mex	1,313	1,402	-	129	-	102	-	1,633
Total-NERC		445,048	452,699	3,286	16,998	3,369	7,658	8,078	492,087
Eastern Interconnection		273,166	280,341	1,760	7,170	931	3,422	2,770	296,393
Quebec Interconnection		22,685	22,930	214	-	489	-	295	23,927
Texas Interconnection		28,665	28,665	58	4,657	-	375	-	33,755
Western Interconnection		120,532	120,763	1,255	5,170	1,949	3,861	5,014	138,012

[33] Refer to *Appendix III* for a detailed listing of Projected Transmission and Transformer Additions

Since last year, approximately 8,800 circuit miles of new transmission were added to the North American bulk power system, with an additional 3,100 miles currently under construction. Of the 8,800 miles, approximately 2,600 miles are greater than 200 kV. This added increase represents a slightly higher than average annual increase. For the ten-year period, approximately 39,000 circuit miles of new high-voltage (greater than 100 kV) transmission is projected, which is slightly higher than the prior ten-year projection. Of this amount, about 27,000 circuit miles are either already Under Construction or Planned—the remaining amounts are considered Conceptual projects (see Figure 20). The most notable increase is shown in SERC, which shows an increase of about 1,000 miles when compared to last year's ten-year projection.

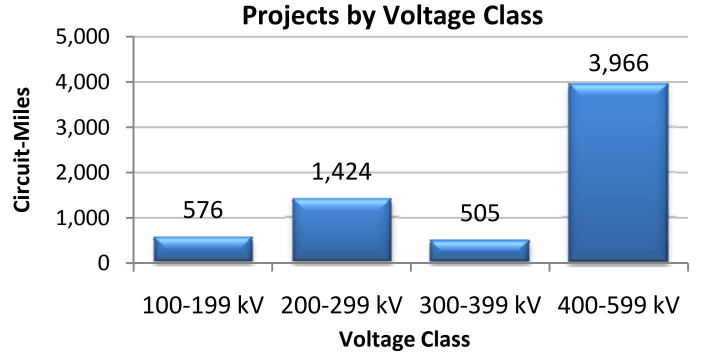
Figure 20: Transmission Line Additions > 100kV - Circuit Miles by Transmission Status



The lines in this figure represent a cumulative value for each year.

For this long-term assessment, NERC collected information on transmission project delays. Across North America, almost 6,500 miles of transmission are currently considered delayed by the Regions (see Figure 21).[34] While a majority of the total miles of delayed transmission is between 400 and 599 kV (approximately 4,000 circuit miles), less than 10 projects are included in this voltage class (see Figure 22). Furthermore, a majority of the lines are experiencing a delay of up to three years. NERC will continue to monitor these delays in subsequent assessments and determine if any delays are significantly impeding transmission development.

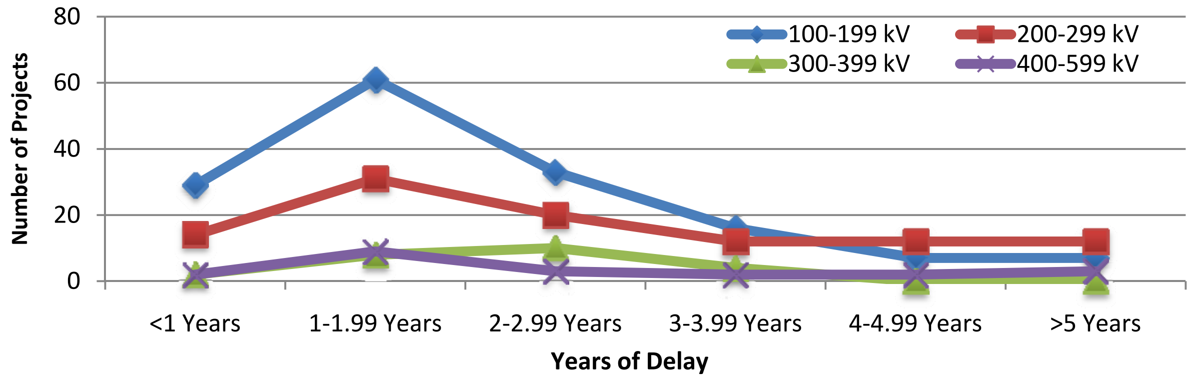
Figure 21: Mileage of Delayed Transmission Projects by Voltage Class



[34] Classifying a transmission project as "Delayed" was at the discretion of the reporting entities. No NERC definition or criteria were developed for this classification.

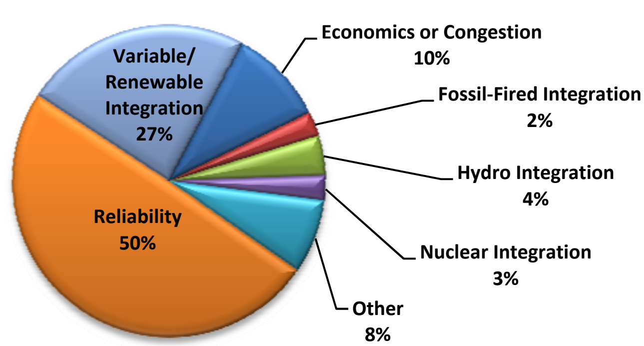
Over 120 projects between 100 and 199 kV are delayed up to three years as well. While longer, higher-voltage transmission lines are generally used to carry larger amounts of power great distances, lower-voltage transmission lines are critical to the operational reliability of a given system. These shorter, lower-voltage transmission lines offer reliability benefits including enhanced transmission efficiency, congestion relief, and greater operator flexibility. However, because the location of these transmission lines are generally in more populated areas, delays in construction are more likely than higher-voltage transmission. Furthermore, at least 40 projects have been identified to be delayed solely because of siting and permitting impediments imposed by local and state regulators, representing about 1,500 miles of transmission. About half of these miles are 100-200 kV, while the other half are at higher voltages.

Figure 22: Transmission Project Delays by Voltage Class and Length of Delay



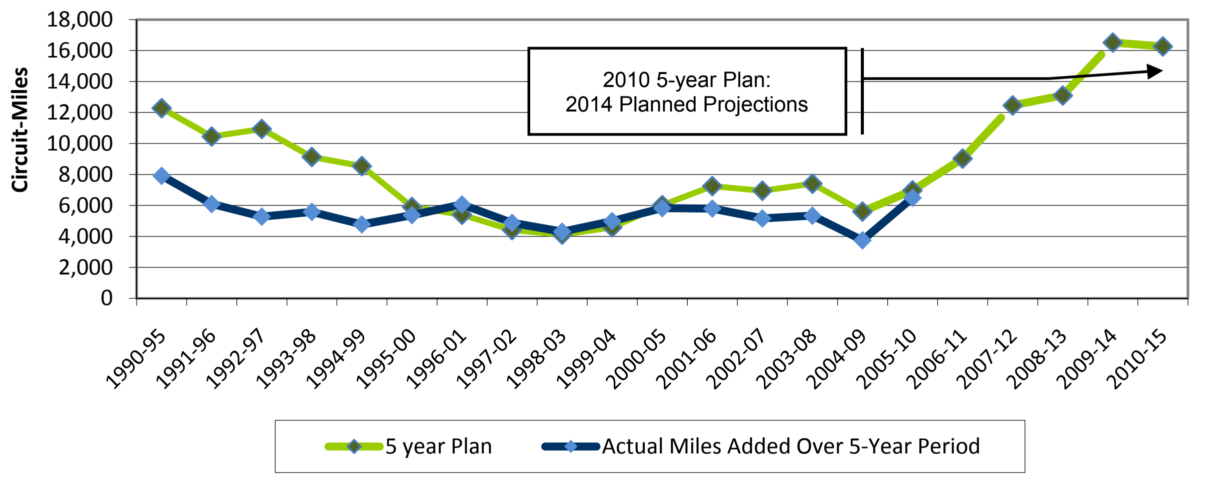
Along with the increased granularity on the status of transmission plans, NERC gathers information on key drivers of individual transmission line and infrastructure development projects. Bulk power system reliability and the integration of variable generation emerged as the predominant reason for the addition of new transmission and transmission upgrades (see Figure 23). Of the total miles of Under Construction, Planned, and Conceptual bulk power transmission, 50 percent is strictly needed for reliability. An additional 27 percent will be needed to integrate variable and renewable generation across North America. When comparing transmission projects that are aimed to integrate variable and renewable generation, the average project length is roughly 70 miles, with only 16 projects larger than 100 miles. A majority of these lines are located in the WECC Region. This is an indication that large, cross-Regional transmission lines are not being projected during the next ten years.

Figure 23: Relative Transmission Mile Additions >100 kV by Primary Driver



NERC continues to monitor the progress of transmission projects across North America. While transmission planning is dynamic (*i.e.*, projected transmission is needed one year, but can be deferred due to a change in demand forecasts), plans should reflect realistic expectations in order to reliably support system needs in the future. An analysis of the past 15 years shows that additional transmission during the next five years would nearly triple the average miles that has historically been constructed during a five-year period (see Figure 24). Through the period of this analysis, actual miles constructed over five-year periods have roughly averaged 6,000 circuit-miles. During the next five years, just over 16,000 miles are Planned, significantly exceeding historical averages. However, during the previous five year period (2004 through 2009), the industry was successful in meeting its projections and exceeded the average, constructing the most transmission during a five-year period since the 1990 through 1995 five-year period. With the beginnings of an observable upward trend, transmission permitting, siting, and construction must continue as planned.

Figure 24: Historical Actual Miles Added for Rolling 5-Year Periods and Projected 5-Year Plans (200 kV and greater)



Operational Issues

Resource Management

Ancillary services are a vital part of balancing supply and demand and maintaining bulk power system reliability. Organizations have taken advantage of demand aggregation, provision of ancillary services from other jurisdictions and interconnected system operation, for decades. Since each balancing area must compensate for the variability of its own demand and random load variations in individual demands, larger balancing areas with sufficient transmission proportionally require relatively less system balancing through "regulation" and ramping capability than smaller balancing areas. Smaller balancing areas can participate in wider-area arrangements for ancillary services to meet NERC's Control Performance Standards (CPS1 and CPS2).

Larger balancing areas or participating in wide-area arrangements, can offer reliability and economic benefits when integrating large amounts of variable generation (*e.g.*, wind and solar).[35] In addition, they can lead to increased diversity of variable generation resources and provide greater access to more dispatchable resources, increasing the power systems ability to accommodate larger amounts of variable generation without the addition of new sources of system flexibility. Balancing areas should evaluate the reliability and economic issues and opportunities resulting from consolidation or participating in wider-area arrangements such as ACE sharing (such as WECC's ACE Diversity Interchange[36]) or wide-area energy management systems.

In many locations, balancing energy transactions are scheduled on an hourly basis. With the advent of variable generation, more frequent and shorter scheduling intervals for energy transactions may assist in the large-scale integration of variable generation. For example, as noted above, balancing areas that schedule energy transactions on an hourly basis must have sufficient regulation resources to maintain the schedule for the hour. If the scheduling intervals are reduced for example to 10 minutes, economically dispatchable generators in an adjacent balancing area can provide necessary ramping capability through an interconnection.[37] With adequate available transmission capacity, larger balancing areas and more frequent scheduling within and between areas provide more sources of flexibility.

With legislation and regulation supporting the construction of renewable resources, which are variable in nature, Demand Response may be used to provide ancillary services. Demand Response not only provides a way to manage peak demand, but increases operational flexibility by providing ancillary services and contributing to operating reserve portfolios on a daily and real-time basis. For Demand Response to be a viable option, operators will require the same certainty as traditional generation. For Spinning Reserves, Direct Control Demand Response can be a viable option, providing push-of-a-button dispatch. Non-Spinning Reserves have a less stringent performance criterion, permitting other varieties of Demand Response to participate. In some Regions, Energy-Voluntary Demand Response can be also be used by system operators in emergency situations. Though voluntary, requests through public appeals or certain program offerings can also offer an expected demand reduction value that operators can implement during capacity constraints. However, these values are not included in this reliability assessment as capacity as those Demand Response programs have voluntary participation.

Transmission Operations

A number of factors over the past few years have contributed to a trend of operating the transmission systems at higher transfer levels, and for longer periods of time. These increased transfers are the result, in part, of accessing economically-priced electric energy and capacity to achieve operating efficiency. Operating procedures that must be followed become more significant as transmission systems are loaded to higher levels. The risk of operator error or equipment misoperation rises with the increased complexity of operating procedures. Further, as the transmission system is operated at higher

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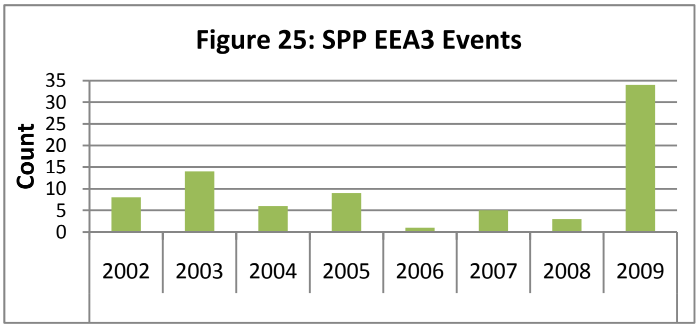
[35] Report for the International Energy Agency by Holttinen et al in 2007

[36] See http://www.wecc.biz/index.php?module=pnForum&func=viewtopic&topic=909

[37] Reduced scheduling intervals would also produce a system response more closely aligned with real-time events and provide closer to real-time market data for providers of Demand Response services

and higher loading levels, the flexibility of the transmission systems to successfully accommodate severe disturbances, such as the loss of multiple transmission lines, is diminished. The overlapping forced outage of multiple transmission lines during conditions of heavy transmission loading has the potential to cause widespread outages of electric service. Further, heavy transmission loading can leave transmission systems exposed to a wide range of operating conditions, and on rare occasions, the systems may be pushed beyond their limits by unforeseen events.

An example of these conditions can be identified within the SPP Acadiana Load Pocket.[38] EEA 3 declarations are firm-load interruptions due to capacity and energy deficiency. Analysis of historical reports identified transmission constraints, extreme weather, significant short-term load forecast errors and unplanned generation outages as the main causes of these emergency events. These conditions resulted in a significant number of Energy Emergency Alert 3s (EEA 3).[39] EEA 3 rose significantly in SPP during 2009 with 34 EEA 3 declarations (Figure 25).[40] The increase is driven, in large part, by the demand in the Acadiana Load Pocket, where SPP anticipates that the ability to adequately meet firm demand will be a concern.



As outlined in SPP's Regional self-assessment, since June 2009, SPP has been working with each entity to resolve the issues and put in place long-term solutions. The SPP Independent Coordinator of Transmission facilitated an agreement with members in the Acadiana Load Pocket to expand and upgrade electric transmission in the area.[41] The joint project includes upgrades to certain existing electric facilities as well as the construction of new substations, transmission lines, and capacitor banks. Each utility is responsible for various components of the project work. All upgrades are expected to be in-service between 2010 and 2012. A description of the detailed expansion plan and upgrades are available on the SPP website.[42] When completed, these upgrades will address the resource and transmission adequacy issues currently experienced in the Acadiana area. SPP is continuing to monitor the Acadiana area (southeastern portion of SPP), due to the reliability concerns and challenges experienced in 2008 and 2009.

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[38] Refer to SPP's Regional Assessment for more details of adequacy issues in the Acadiana Load Pocket.

[39] EEA 3 declarations are firm-load interruptions due to capacity and energy deficiency. EEA 3 is defined in NERC's Reliability Standard EOP-002-2. EEA 3 definition is available at http://www.nerc.com/files/EOP-002-2_1.pdf

[40] The frequency of EEA 3 declarations over a timeframe provides an indication of performance measured at a balancing authority (BA) or interconnection level.

[41] In this case, additional transmission was determined to be the solution to alleviate transmission constraints; however, additional local generation or Demand-Side Management may alleviate constraints in some cases.

[42] http://www.spp.org/publications/SPP_Acadiana_news_release_1-19-09.pdf

ESTIMATED DEMAND, RESOURCES AND RESERVE MARGINS

To improve consistency and increase granularity and transparency, the NERC Planning Committee approved these categories for capacity resources and transactions (see Table 4 and below—summary only):

1. **Existing:**
   a. **Existing-Certain** — Existing generation resources available to operate and deliver power within or into the Region during the period of analysis in the assessment.

   b. **Existing-Other** — Existing generation resources that may be available to operate and deliver power within or into the Region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons.

   c. **Existing, but Inoperable** — Existing portion of generation resources that are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment.

2. **Future:**
   a. **Future-Planned** — Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of analysis in the assessment.

   b. **Future-Other** — Future generating resources that do not qualify in Future-Planned and are not included in the Conceptual category.

3. **Conceptual:**
   a. **Conceptual** — Less certain generation resources identified in generation interconnection queue, corporate announcement, or other early stage development.

Table 4: Demand and Resource Categories

Total Internal Demand (MW) — 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. Total Internal Demand includes adjustments for indirect Demand-Side Management programs such as conservation programs, improvements in efficiency of electric energy use, and all non-dispatchable Demand Response programs

Net Internal Demand (MW) — Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce peak load

Existing-Certain and Net Firm Transactions (MW) — Existing-Certain capacity resources plus Firm Imports, minus Firm Exports.

Anticipated Capacity Resources (MW) — Existing-Certain and Net Firm Transactions plus Future, Planned capacity resources plus Expected Imports, minus Expected Exports

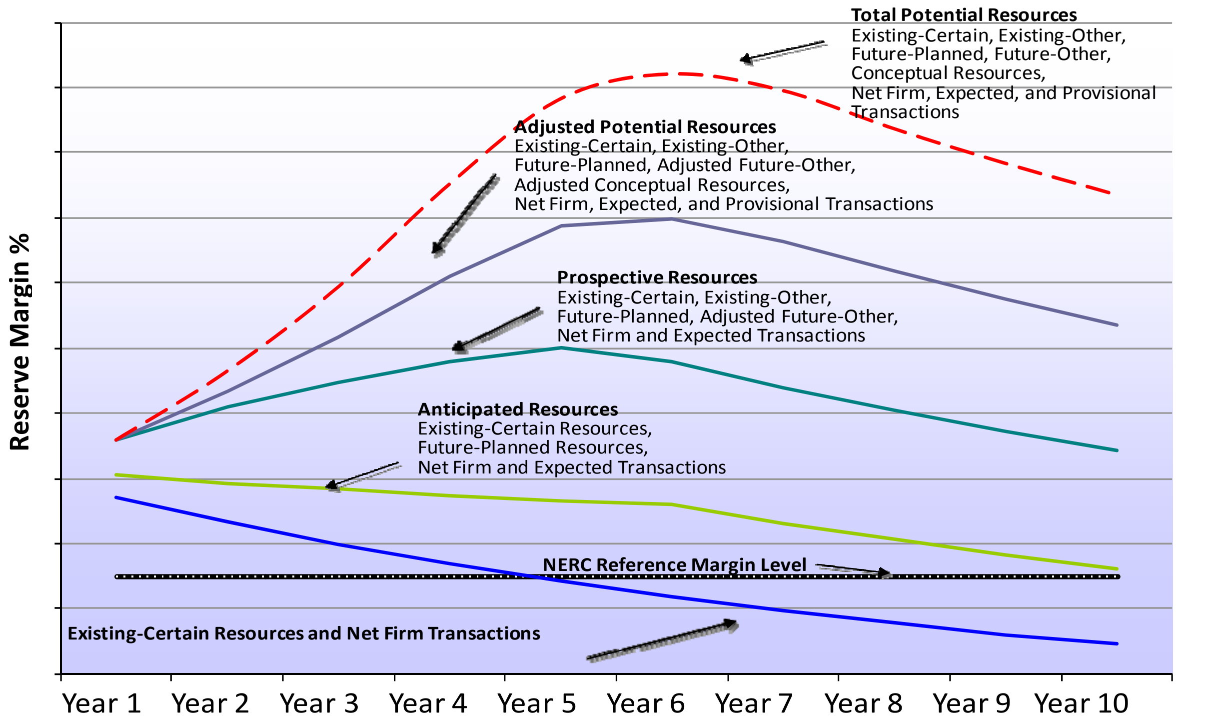
Prospective Capacity Resources (MW) — Anticipated Capacity Resources plus Existing-Other capacity resources, plus Future-Other capacity resources, minus all deratings

Total Potential Capacity Resources (MW) — Prospective Capacity Resources plus Conceptual Capacity Resources plus Potential Imports, minus Potential Exports

Adjusted Potential Capacity Resources (MW) — Prospective Capacity Resources plus Adjusted (based on a Regionally defined confidence factor) Conceptual Capacity Resources

Reserve Margins, developed for this analysis, are categorized based on the certainty that future resources expected to be available to deliver power within the assessment timeframe are actually constructed and deployed. Projected Reserve Margins are shown in Tables 5a through 5f, representing first, fifth, and tenth year projections. An example Reserve Margin chart is shown in Figure 26.

Figure 26: Example Margins Chart Including Definitions



Future Reserve Margins are then compared to the NERC Reference Margin Level which is defined as either the Target Reserve Margin provided by the Region/subregion or a NERC assigned value based on capacity mix (*i.e.*, thermal/hydro). Each Region/subregion may have their own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the Regional/subregional Target Reserve Margin level is adopted as the NERC Reference Reserve Margin Level. If not, NERC assigned 15 percent Reserve Margin for predominately thermal systems and for predominately hydro systems, 10 percent. This reference level then serves as the basis for determining whether more resources (*e.g.*, generation, Demand-Side Management, transfers) may be needed within that Region\subregion.

As the Planning Reserve Margin is a capacity based metric, the Planning Reserve Margin metric does not provide a comprehensive assessment of performance in energy-limited systems, *e.g.,* hydro capacity with limited water resources or systems with significant variable generation penetration.[43]

[43] See page 8 of NERC's 2010 Annual Report on Bulk Power System Reliability Metrics Report at http://www.nerc.com/docs/pc/rmwg/RMWG_AnnualReport6.1.pdf)

Table 5a: Estimated 2010 Summer Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Transactions (MW)	Anticipated Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Transactions (%)	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
FRCC	46,006	42,820	53,370	53,826	55,264	55,264	55,264	24.6%	25.7%	29.1%	29.1%	29.1%	15.0%
MRO	42,240	39,343	50,633	50,633	50,633	50,633	50,633	28.7%	28.7%	28.7%	28.7%	28.7%	15.0%
NPCC	60,215	60,001	73,341	73,341	73,882	73,882	73,882	22.2%	22.2%	23.1%	23.1%	23.1%	15.0%
New England	27,190	27,190	32,539	32,539	33,080	33,080	33,080	19.7%	19.7%	21.7%	21.7%	21.7%	15.0%
New York	33,025	32,811	40,802	40,802	40,802	40,802	40,802	24.4%	24.4%	24.4%	24.4%	24.4%	18.0%
RFC	177,688	171,488	219,583	219,583	228,983	228,983	228,983	28.0%	28.0%	33.5%	33.5%	33.5%	15.0%
SERC	201,350	195,833	246,439	247,674	257,068	257,068	257,097	25.8%	26.5%	31.3%	31.3%	31.3%	15.0%
Central	42,364	41,298	51,401	51,761	52,241	52,241	52,241	24.5%	25.3%	26.5%	26.5%	26.5%	15.0%
Delta	27,945	27,231	40,115	40,115	43,867	43,867	43,867	47.3%	47.3%	61.1%	61.1%	61.1%	15.0%
Gateway	19,113	19,003	21,795	21,807	21,899	21,899	21,899	14.7%	14.8%	15.2%	15.2%	15.2%	11.9%
Southeastern	48,472	46,807	60,151	60,973	64,264	64,264	64,264	28.5%	30.3%	37.3%	37.3%	37.3%	15.0%
VACAR	63,456	61,494	72,978	73,019	74,798	74,798	74,827	18.7%	18.7%	21.6%	21.6%	21.7%	15.0%
SPP	43,395	42,976	52,913	53,298	57,844	57,844	57,844	23.1%	24.0%	34.6%	34.6%	34.6%	13.6%
TRE	63,810	62,412	75,181	75,181	84,164	84,193	84,298	20.5%	20.5%	34.9%	34.9%	35.1%	12.5%
WECC	129,072	124,924	160,611	161,358	161,358	161,358	161,358	28.6%	29.2%	29.2%	29.2%	29.2%	14.7%
Basin	13,662	12,642	15,547	15,824	15,824	15,824	15,824	23.0%	25.2%	25.2%	25.2%	25.2%	12.0%
Cal N	25,310	24,339	29,673	30,068	30,068	30,068	30,068	21.9%	23.5%	23.5%	23.5%	23.5%	14.6%
Cal S	33,280	31,660	41,051	41,464	41,464	41,464	41,464	29.7%	31.0%	31.0%	31.0%	31.0%	14.8%
Desert DW	27,997	27,470	33,975	33,989	33,989	33,989	33,989	23.7%	23.7%	23.7%	23.7%	23.7%	13.6%
Northwest	23,855	23,852	32,723	32,963	32,963	32,963	32,963	37.2%	38.2%	38.2%	38.2%	38.2%	18.6%
Rockies	10,979	10,607	14,480	14,557	14,557	14,557	14,557	36.5%	37.2%	37.2%	37.2%	37.2%	12.3%
Total-U.S.	763,776	739,798	932,071	934,894	969,197	969,226	969,360	26.0%	26.4%	31.0%	31.0%	31.0%	15.0%
Canada													
MRO	6,189	5,887	7,692	7,745	7,745	7,745	7,745	30.6%	31.6%	31.6%	31.6%	31.6%	10.0%
NPCC	47,762	47,361	68,377	68,417	68,417	68,572	68,572	44.4%	44.5%	44.5%	44.8%	44.8%	15.0%
Maritimes	3,664	3,264	7,041	7,041	7,041	7,041	7,041	115.7%	115.7%	115.7%	115.7%	115.7%	15.0%
Ontario	23,498	23,498	31,785	31,785	31,785	31,940	31,940	35.3%	35.3%	35.3%	35.9%	35.9%	18.5%
Quebec	20,599	20,599	29,551	29,591	29,591	29,591	29,591	43.5%	43.7%	43.7%	43.7%	43.7%	10.0%
WECC	17,683	17,676	21,059	21,572	21,572	21,572	21,572	19.1%	22.0%	22.0%	22.0%	22.0%	11.5%
Total-Canada	71,634	70,925	97,128	97,734	97,734	97,889	97,889	36.9%	37.8%	37.8%	38.0%	38.0%	15.0%
Mexico													
WECC CA-MX Mex	2,140	2,140	2,608	2,554	2,554	2,554	2,554	21.9%	19.3%	19.3%	19.3%	19.3%	14.8%
Total-NERC	837,551	812,862	1,031,806	1,035,182	1,069,485	1,069,669	1,069,803	26.9%	27.4%	31.6%	31.6%	31.6%	15.0%

Table 5b: Estimated 2010/2011 Winter Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Transactions (MW)	Anticipated Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Transactions (%)	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
FRCC	46,235	42,716	57,358	57,952	59,323	59,323	59,323	34.3%	35.7%	38.9%	38.9%	38.9%	15.0%
MRO	35,722	34,091	52,362	52,585	52,585	55,507	62,327	53.6%	54.2%	54.2%	62.8%	82.8%	15.0%
NPCC	46,374	46,374	73,083	73,083	73,667	73,667	73,667	57.6%	57.6%	58.9%	58.9%	58.9%	15.0%
New England	22,085	22,085	32,612	32,612	33,196	33,196	33,196	47.7%	47.7%	50.3%	50.3%	50.3%	15.0%
New York	24,289	24,289	40,471	40,471	40,471	40,471	40,471	66.6%	66.6%	66.6%	66.6%	66.6%	18.0%
RFC	143,040	143,040	218,752	218,752	228,152	228,152	228,152	52.9%	52.9%	59.5%	59.5%	59.5%	15.0%
SERC	183,614	178,614	252,201	253,918	263,752	263,752	263,781	41.2%	42.2%	47.7%	47.7%	47.7%	15.0%
Central	43,475	42,453	53,590	53,978	54,530	54,530	54,530	26.2%	27.1%	28.4%	28.4%	28.4%	15.0%
Delta	23,131	22,561	41,652	41,652	45,654	45,654	45,654	84.6%	84.6%	102.4%	102.4%	102.4%	15.0%
Gateway	15,545	15,470	22,112	22,124	22,216	22,216	22,216	42.9%	43.0%	43.6%	43.6%	43.6%	11.9%
Southeastern	42,482	40,817	59,875	61,145	64,553	64,553	64,553	46.7%	49.8%	58.2%	58.2%	58.2%	15.0%
VACAR	58,981	57,313	74,972	75,019	76,799	76,799	76,827	30.8%	30.9%	34.0%	34.0%	34.0%	15.0%
SPP	31,415	31,197	53,760	56,009	60,789	61,144	64,334	72.3%	79.5%	94.9%	96.0%	106.2%	13.6%
TRE	43,823	43,487	78,816	76,385	84,805	85,134	86,300	81.2%	75.6%	95.0%	95.8%	98.4%	12.5%
WECC	106,139	100,580	158,831	159,643	159,643	159,643	159,643	57.9%	58.7%	58.7%	58.7%	58.7%	14.1%
Basin	10,633	10,345	14,602	14,652	14,652	14,652	14,652	41.1%	41.6%	41.6%	41.6%	41.6%	11.5%
Cal N	18,088	17,597	27,783	27,915	27,915	27,915	27,915	57.9%	58.6%	58.6%	58.6%	58.6%	10.5%
Cal S	22,602	19,861	47,562	47,422	47,422	47,422	47,422	139.5%	138.8%	138.8%	138.8%	138.8%	11.4%
Desert DW	17,253	16,764	29,083	29,585	29,585	29,585	29,585	73.5%	76.5%	76.5%	76.5%	76.5%	13.0%
Northwest	28,649	28,646	35,039	35,239	35,239	35,239	35,239	22.3%	23.0%	23.0%	23.0%	23.0%	20.0%
Rockies	9,795	9,470	15,108	15,391	15,391	15,391	15,391	59.5%	62.5%	62.5%	62.5%	62.5%	13.5%
Total-U.S.	636,362	620,100	945,163	948,326	982,716	986,321	997,526	52.4%	52.9%	58.5%	59.1%	60.9%	15.0%
Canada													
MRO	7,560	7,256	8,969	9,074	9,074	9,074	9,074	23.6%	25.0%	25.0%	25.0%	25.0%	10.0%
NPCC	65,073	62,938	78,283	76,716	78,744	78,888	78,888	24.4%	21.9%	25.1%	25.3%	25.3%	15.0%
Maritimes	5,655	5,270	7,057	7,243	7,243	7,243	7,243	33.9%	37.4%	37.4%	37.4%	37.4%	15.0%
Ontario	22,473	22,473	32,777	30,968	30,968	31,112	31,112	45.8%	37.8%	37.8%	38.4%	38.4%	18.9%
Quebec	36,945	35,195	38,450	38,505	40,533	40,533	40,533	9.2%	9.4%	15.2%	15.2%	15.2%	10.0%
WECC	21,243	21,243	23,950	24,463	24,463	24,463	24,463	12.7%	15.2%	15.2%	15.2%	15.2%	13.2%
Total-Canada	93,876	91,438	111,202	110,253	112,281	112,425	112,425	21.6%	20.6%	22.8%	23.0%	23.0%	15.0%
Mexico													
WECC CA-MX Mex	1,472	1,472	2,771	2,771	2,771	2,771	2,771	88.2%	88.2%	88.2%	88.2%	88.2%	11.4%
Total-NERC	731,711	713,009	1,059,136	1,061,350	1,097,768	1,101,517	1,112,722	48.5%	48.9%	54.0%	54.5%	56.1%	15.0%

Table 5c: Estimated 2014 Summer Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Transactions (MW)	Anticipated Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Transactions (%)	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
FRCC	48,059	44,451	53,367	57,097	58,535	58,535	58,535	20.1%	28.5%	31.7%	31.7%	31.7%	15.0%
MRO	44,627	41,675	51,011	51,986	51,986	53,464	56,526	22.4%	24.7%	24.7%	28.3%	35.6%	15.0%
NPCC	62,922	62,708	73,646	78,374	78,671	81,584	93,238	17.4%	25.0%	25.5%	30.1%	48.7%	15.0%
New England	29,025	29,025	32,485	35,291	35,588	37,008	42,690	11.9%	21.6%	22.6%	27.5%	47.1%	15.0%
New York	33,897	33,683	41,162	43,083	43,083	44,576	50,548	22.2%	27.9%	27.9%	32.3%	50.1%	18.0%
RFC	192,000	182,700	219,583	232,924	242,324	244,872	251,535	20.2%	27.5%	32.6%	34.0%	37.7%	15.0%
SERC	218,126	211,512	248,600	262,024	273,536	273,611	277,768	17.5%	23.9%	29.3%	29.4%	31.3%	15.0%
Central	46,314	44,929	51,469	54,872	55,352	55,352	55,352	14.6%	22.1%	23.2%	23.2%	23.2%	15.0%
Delta	30,393	29,616	39,237	40,016	45,905	45,905	47,505	32.5%	35.1%	55.0%	55.0%	60.4%	15.0%
Gateway	19,376	19,263	23,531	25,249	25,341	25,341	25,363	22.2%	31.1%	31.6%	31.6%	31.7%	11.9%
Southeastern	53,168	51,397	60,430	64,946	68,218	68,218	68,831	17.6%	26.4%	32.7%	32.7%	33.9%	15.0%
VACAR	68,875	66,307	73,933	76,941	78,720	78,795	80,718	11.5%	16.0%	18.7%	18.8%	21.7%	15.0%
SPP	46,579	46,102	53,573	58,368	62,915	64,687	80,639	16.2%	26.6%	36.5%	40.3%	74.9%	13.6%
TRE	69,209	67,655	75,181	76,191	85,174	88,639	100,927	11.1%	12.6%	25.9%	31.0%	49.2%	12.5%
WECC	136,402	130,302	160,065	181,327	181,327	182,730	182,730	22.8%	39.2%	39.2%	40.2%	40.2%	14.7%
Basin	14,966	13,760	16,652	17,695	17,695	17,831	17,831	21.0%	28.6%	28.6%	29.6%	29.6%	12.0%
Cal N	26,645	25,472	29,184	37,873	37,873	37,873	37,873	14.6%	48.7%	48.7%	48.7%	48.7%	14.6%
Cal S	34,976	32,073	40,325	54,267	54,267	54,347	54,347	25.7%	69.2%	69.2%	69.4%	69.4%	14.8%
Desert DW	29,704	28,957	34,121	38,298	38,298	39,623	39,623	17.8%	32.3%	32.3%	36.8%	36.8%	13.6%
Northwest	24,992	24,947	32,478	33,689	33,689	33,689	33,689	30.2%	35.0%	35.0%	35.0%	35.0%	18.6%
Rockies	12,358	11,899	14,627	16,304	16,304	16,434	16,434	22.9%	37.0%	37.0%	38.1%	38.1%	12.3%
Total-U.S.	817,924	787,105	935,027	998,292	1,034,468	1,048,122	1,101,899	18.8%	26.8%	31.4%	33.2%	40.0%	15.0%
Canada													
MRO	6,847	6,545	7,802	8,497	8,497	8,497	8,497	19.2%	29.8%	29.8%	29.8%	29.8%	10.0%
NPCC	47,542	47,161	69,252	67,771	67,771	68,855	68,855	46.8%	43.7%	43.7%	46.0%	46.0%	15.0%
Maritimes	3,619	3,238	7,241	7,655	7,655	7,655	7,655	123.6%	136.4%	136.4%	136.4%	136.4%	15.0%
Ontario	22,545	22,545	31,785	28,246	28,246	29,330	29,330	41.0%	25.3%	25.3%	30.1%	30.1%	17.8%
Quebec	21,378	21,378	30,226	31,870	31,870	31,870	31,870	41.4%	49.1%	49.1%	49.1%	49.1%	11.8%
WECC	19,817	19,812	20,894	22,940	22,940	23,553	23,553	5.5%	15.8%	15.8%	18.9%	18.9%	11.5%
Total-Canada	74,206	73,518	97,948	99,207	99,207	100,905	100,905	33.2%	34.9%	34.9%	37.3%	37.3%	15.0%
Mexico													
WECC CA-MX Mex	2,511	2,511	2,608	3,461	3,461	3,671	3,671	3.9%	37.8%	37.8%	46.2%	46.2%	14.8%
Total-NERC	894,641	863,133	1,035,583	1,100,960	1,137,136	1,152,698	1,206,475	20.0%	27.6%	31.7%	33.5%	39.8%	15.0%

Table 5d: Estimated 2014/2015 Winter Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Transactions (MW)	Anticipated Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Transactions (%)	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
FRCC	48,992	45,174	57,290	61,628	62,999	62,999	62,999	26.8%	36.4%	39.5%	39.5%	39.5%	15.0%
MRO	38,324	36,614	52,163	53,475	53,475	59,420	73,059	42.5%	46.1%	46.1%	62.3%	99.5%	15.0%
NPCC	47,401	47,401	73,674	78,943	79,275	83,389	99,845	55.4%	66.5%	67.2%	75.9%	110.6%	15.0%
New England	22,505	22,505	32,558	35,802	36,134	38,974	50,338	44.7%	59.1%	60.6%	73.2%	123.7%	15.0%
New York	24,896	24,896	41,116	43,142	43,142	44,415	49,508	65.2%	73.3%	73.3%	78.4%	98.9%	18.0%
RFC	151,400	151,400	218,752	231,795	241,195	241,195	259,618	44.5%	53.1%	59.3%	59.3%	71.5%	15.0%
SERC	195,703	189,890	255,770	269,724	281,674	281,674	286,213	34.7%	42.0%	48.3%	48.3%	50.7%	15.0%
Central	45,662	44,623	53,830	57,462	58,014	58,014	58,014	20.6%	28.8%	30.0%	30.0%	30.0%	15.0%
Delta	25,411	24,830	40,388	41,167	47,304	47,304	48,904	62.7%	65.8%	90.5%	90.5%	97.0%	15.0%
Gateway	16,093	16,018	24,016	25,734	25,826	25,826	26,105	49.9%	60.7%	61.2%	61.2%	63.0%	11.9%
Southeastern	45,823	44,047	60,423	65,047	68,436	68,436	69,049	37.2%	47.7%	55.4%	55.4%	56.8%	15.0%
VACAR	62,714	60,372	77,113	80,315	82,095	82,095	84,141	27.7%	33.0%	36.0%	36.0%	39.4%	15.0%
SPP	34,951	34,703	54,338	59,245	64,025	66,407	87,845	56.6%	70.7%	84.5%	91.4%	153.1%	13.6%
TRE	46,578	46,086	78,816	79,976	88,397	94,365	115,525	71.0%	73.5%	91.8%	104.8%	150.7%	12.5%
WECC	112,673	109,208	159,279	179,961	179,961	181,321	181,321	45.8%	64.8%	64.8%	66.0%	66.0%	14.1%
Basin	11,857	11,481	16,338	16,996	16,996	16,996	16,996	42.3%	48.0%	48.0%	48.0%	48.0%	11.5%
Cal N	19,037	18,617	27,807	34,838	34,838	34,838	34,838	49.4%	87.1%	87.1%	87.1%	87.1%	10.5%
Cal S	23,715	22,004	46,970	54,063	54,063	54,130	54,130	113.5%	145.7%	145.7%	146.0%	146.0%	11.4%
Desert DW	18,401	17,785	28,800	32,352	32,352	33,346	33,346	61.9%	81.9%	81.9%	87.5%	87.5%	13.0%
Northwest	29,907	29,842	38,190	38,821	38,821	38,821	38,821	28.0%	30.1%	30.1%	30.1%	30.1%	20.0%
Rockies	10,580	10,303	15,272	16,181	16,181	16,370	16,370	48.2%	57.1%	57.1%	58.9%	58.9%	13.5%
Total-U.S.	676,022	660,476	950,081	1,014,747	1,051,001	1,070,770	1,166,425	43.8%	53.6%	59.1%	62.1%	76.6%	15.0%
Canada													
MRO	8,308	8,004	8,949	9,841	9,841	9,841	9,841	11.8%	22.9%	22.9%	22.9%	22.9%	10.0%
NPCC	65,572	63,709	78,458	78,262	80,290	82,473	82,473	23.1%	22.8%	26.0%	29.5%	29.5%	15.0%
Maritimes	5,449	5,086	7,257	7,671	7,671	7,671	7,671	42.7%	50.8%	50.8%	50.8%	50.8%	15.0%
Ontario	21,336	21,336	32,777	29,064	29,064	31,247	31,247	53.6%	36.2%	36.2%	46.5%	46.5%	17.0%
Quebec	38,788	37,288	38,425	41,528	43,556	43,556	43,556	3.0%	11.4%	16.8%	16.8%	16.8%	11.8%
WECC	23,420	23,420	23,413	26,987	26,987	27,837	27,837	0.0%	15.2%	15.2%	18.9%	18.9%	13.2%
Total-Canada	97,301	95,134	110,820	115,090	117,118	120,151	120,151	16.5%	21.0%	23.1%	26.3%	26.3%	15.0%
Mexico													
WECC CA-MX Mex	1,617	1,617	2,548	3,334	3,334	3,558	3,558	57.6%	106.2%	106.2%	120.0%	120.0%	11.4%
Total-NERC	774,940	757,226	1,063,448	1,133,172	1,171,454	1,194,480	1,290,135	40.4%	49.6%	54.7%	57.7%	70.4%	15.0%

Table 5e: Estimated 2019 Summer Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Transactions (MW)	Anticipated Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Transactions (%)	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
FRCC	51,982	47,988	53,567	60,073	61,511	61,511	61,511	11.6%	25.2%	28.2%	28.2%	28.2%	15.0%
MRO	46,990	44,013	49,483	51,207	51,207	52,968	56,342	12.4%	16.3%	16.3%	20.3%	28.0%	15.0%
NPCC	65,716	65,502	73,318	78,046	78,343	81,918	96,217	11.9%	19.2%	19.6%	25.1%	46.9%	15.0%
New England	30,730	30,730	32,157	34,963	35,260	36,787	42,898	4.6%	13.8%	14.7%	19.7%	39.6%	15.0%
New York	34,986	34,772	41,162	43,083	43,083	45,130	53,319	18.4%	23.9%	23.9%	29.8%	53.3%	18.0%
RFC	200,600	191,300	219,583	235,318	244,718	250,277	262,433	14.8%	23.0%	27.9%	30.8%	37.2%	15.0%
SERC	234,674	227,605	247,370	270,495	283,726	283,726	295,861	8.7%	18.8%	24.7%	24.7%	30.0%	15.0%
Central	49,951	48,576	51,485	54,898	55,378	55,378	56,092	6.0%	13.0%	14.0%	14.0%	15.5%	15.0%
Delta	32,266	31,474	37,136	37,915	45,425	45,425	49,430	18.0%	20.5%	44.3%	44.3%	57.0%	15.0%
Gateway	20,032	19,917	23,570	25,288	25,380	25,380	25,428	18.3%	27.0%	27.4%	27.4%	27.7%	11.9%
Southeastern	58,046	55,976	61,489	70,142	73,512	73,512	76,444	9.8%	25.3%	31.3%	31.3%	36.6%	15.0%
VACAR	74,379	71,662	73,690	82,252	84,031	84,031	88,468	2.8%	14.8%	17.3%	17.3%	23.5%	15.0%
SPP	49,739	49,247	54,540	60,580	65,126	67,162	85,482	10.7%	23.0%	32.2%	36.4%	73.6%	13.6%
TRE	74,467	72,613	75,181	76,861	85,844	91,222	110,291	3.5%	5.9%	18.2%	25.6%	51.9%	12.5%
WECC	145,237	138,684	160,643	184,254	184,254	188,306	188,306	15.8%	32.9%	32.9%	35.8%	35.8%	14.7%
Basin	16,159	14,901	16,568	17,266	17,266	17,821	17,821	11.2%	15.9%	15.9%	19.6%	19.6%	12.0%
Cal N	27,502	26,296	27,603	36,691	36,691	36,703	36,703	5.0%	39.5%	39.5%	39.6%	39.6%	14.6%
Cal S	37,133	33,846	37,251	55,086	55,086	55,382	55,382	10.1%	62.8%	62.8%	63.6%	63.6%	14.8%
Desert DW	32,552	31,725	37,833	45,320	45,320	48,293	48,293	19.3%	42.9%	42.9%	52.2%	52.2%	13.6%
Northwest	26,359	26,314	32,677	34,075	34,075	34,075	34,075	24.2%	29.5%	29.5%	29.5%	29.5%	18.6%
Rockies	13,642	13,269	14,137	15,999	15,999	16,519	16,519	6.5%	20.6%	20.6%	24.5%	24.5%	12.3%
Total-U.S.	869,405	836,951	933,687	1,016,833	1,054,729	1,077,089	1,156,443	11.6%	21.5%	26.0%	28.7%	38.2%	15.0%
Canada													
MRO	7,402	7,100	8,852	9,263	9,263	9,263	10,063	24.7%	30.5%	30.5%	30.5%	41.7%	10.0%
NPCC	48,289	47,971	69,252	66,313	66,313	70,648	70,648	44.4%	38.2%	38.2%	47.3%	47.3%	15.0%
Maritimes	3,550	3,232	7,241	7,655	7,655	7,655	7,655	124.0%	136.9%	136.9%	136.9%	136.9%	15.0%
Ontario	22,282	22,282	31,785	24,136	24,136	28,472	28,472	42.7%	8.3%	8.3%	27.8%	27.8%	17.0%
Quebec	22,457	22,457	30,226	34,521	34,521	34,521	34,521	34.6%	53.7%	53.7%	53.7%	53.7%	11.8%
WECC	22,194	22,189	20,879	22,913	22,913	23,732	23,732	-5.9%	3.3%	3.3%	7.0%	7.0%	11.5%
Total-Canada	77,885	77,260	98,983	98,489	98,489	103,643	104,443	28.1%	27.5%	27.5%	34.1%	35.2%	15.0%
Mexico													
WECC CA-MX Mex	3,125	3,125	2,608	4,027	4,027	4,814	4,814	-16.5%	28.9%	28.9%	54.0%	54.0%	14.8%
Total-NERC	950,415	917,336	1,035,277	1,119,349	1,157,244	1,185,547	1,265,701	12.9%	22.0%	26.2%	29.2%	38.0%	15.0%

Table 5f: Estimated 2019/2020 Winter Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Transactions (MW)	Anticipated Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Transactions (%)	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
FRCC	53,216	49,082	57,540	64,804	66,175	66,175	66,175	17.2%	32.0%	34.8%	34.8%	34.8%	15.0%
MRO	40,207	38,423	52,163	53,025	53,025	59,120	72,759	35.8%	38.0%	38.0%	53.9%	89.4%	15.0%
NPCC	48,969	48,969	73,346	78,615	78,947	83,830	103,360	49.8%	60.5%	61.2%	71.2%	111.1%	15.0%
New England	23,070	23,070	32,230	35,474	35,806	38,861	51,082	39.7%	53.8%	55.2%	68.4%	121.4%	15.0%
New York	25,899	25,899	41,116	43,142	43,142	44,969	52,279	58.8%	66.6%	66.6%	73.6%	101.9%	18.0%
RFC	157,200	157,200	218,752	234,189	243,589	243,589	279,020	39.2%	49.0%	55.0%	55.0%	77.5%	15.0%
SERC	207,797	201,577	254,197	277,954	291,657	291,657	304,747	26.1%	37.9%	44.7%	44.7%	51.2%	15.0%
Central	47,096	46,056	53,839	57,481	58,033	58,033	58,821	16.9%	24.8%	26.0%	26.0%	27.7%	15.0%
Delta	26,681	26,125	38,721	39,500	47,292	47,292	51,297	48.2%	51.2%	81.0%	81.0%	96.4%	15.0%
Gateway	16,683	16,608	24,026	25,744	25,836	25,836	26,435	44.7%	55.0%	55.6%	55.6%	59.2%	11.9%
Southeastern	49,996	47,915	60,740	69,602	73,090	73,090	76,098	26.8%	45.3%	52.5%	52.5%	58.8%	15.0%
VACAR	67,341	64,873	76,872	85,627	87,407	87,407	92,097	18.5%	32.0%	34.7%	34.7%	42.0%	15.0%
SPP	37,544	37,294	55,477	61,672	66,452	69,820	100,128	48.8%	65.4%	78.2%	87.2%	168.5%	13.6%
TRE	50,099	49,307	78,816	80,756	89,177	98,049	129,505	59.8%	63.8%	80.9%	98.9%	162.7%	12.5%
WECC	120,587	117,072	159,172	181,542	181,542	185,346	185,346	36.0%	55.1%	55.1%	58.3%	58.3%	14.1%
Basin	12,880	12,495	16,428	17,622	17,622	18,203	18,203	31.5%	41.0%	41.0%	45.7%	45.7%	11.5%
Cal N	20,177	19,740	27,824	35,121	35,121	35,122	35,122	41.0%	77.9%	77.9%	77.9%	77.9%	10.5%
Cal S	25,126	23,377	47,202	58,008	58,008	58,040	58,040	101.9%	148.1%	148.1%	148.3%	148.3%	11.4%
Desert DW	20,253	19,617	27,048	30,225	30,225	33,350	33,350	37.9%	54.1%	54.1%	70.0%	70.0%	13.0%
Northwest	31,514	31,449	38,844	38,593	38,593	38,583	38,583	23.5%	22.7%	22.7%	22.7%	22.7%	20.0%
Rockies	11,805	11,562	15,839	16,991	16,991	17,209	17,209	37.0%	47.0%	47.0%	48.8%	48.8%	13.5%
Total-U.S.	715,619	698,924	949,462	1,032,557	1,070,564	1,097,585	1,241,040	35.8%	47.7%	53.2%	57.0%	77.6%	15.0%
Canada													
MRO	8,910	8,606	8,999	10,388	10,388	11,988	11,988	4.6%	20.7%	20.7%	39.3%	39.3%	10.0%
NPCC	66,012	64,459	79,005	78,208	80,236	89,677	89,677	22.6%	21.3%	24.5%	39.1%	39.1%	15.0%
Maritimes	5,421	5,119	7,257	7,671	7,671	7,671	7,671	41.8%	49.8%	49.8%	49.8%	49.8%	15.0%
Ontario	20,491	20,491	32,777	27,583	27,583	37,024	37,024	60.0%	34.6%	34.6%	80.7%	80.7%	17.0%
Quebec	40,099	38,849	38,972	42,954	44,982	44,982	44,982	0.3%	10.6%	15.8%	15.8%	15.8%	11.8%
WECC	25,863	25,863	23,357	27,111	27,111	28,280	28,280	-9.7%	4.8%	4.8%	9.3%	9.3%	13.2%
Total-Canada	100,784	98,928	111,361	115,707	117,735	129,945	129,945	12.6%	17.0%	19.0%	31.4%	31.4%	15.0%
Mexico													
WECC CA-MX Mex	1,817	1,817	3,047	4,174	4,174	5,018	5,018	67.7%	129.7%	129.7%	176.2%	176.2%	11.4%
Total-NERC	818,221	799,669	1,063,870	1,152,438	1,192,474	1,232,549	1,376,003	33.0%	44.1%	49.1%	54.1%	72.1%	15.0%

2010 EMERGING RELIABILITY ISSUES

INTRODUCTION

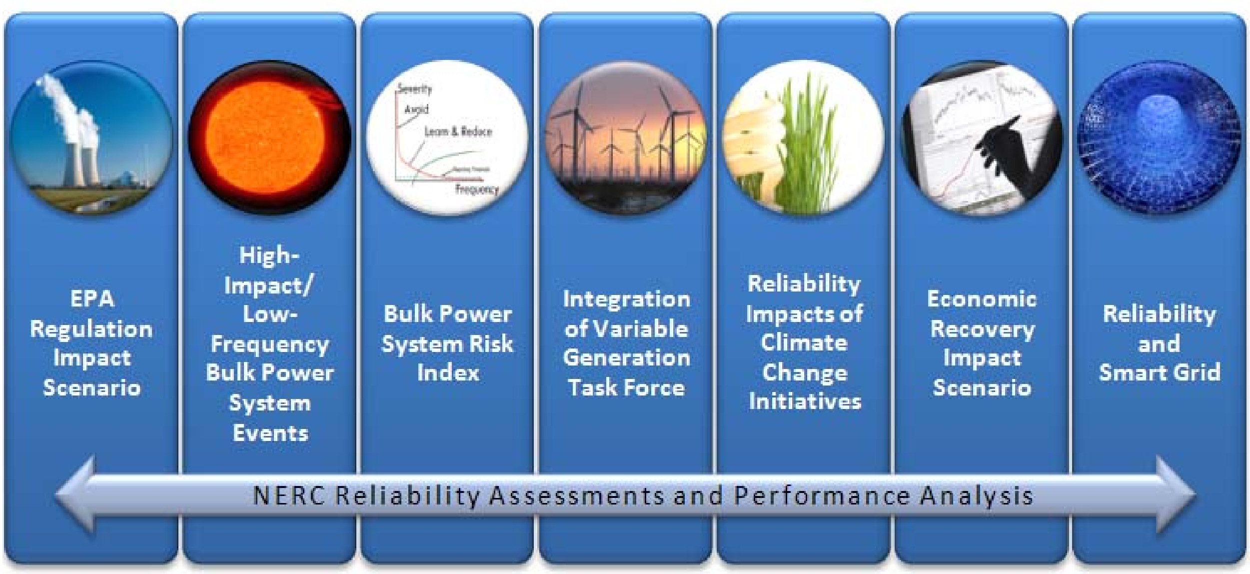
The NERC Reliability Assessment and Performance Analysis program reviews, assesses, and reports on the overall electric reliability of the interconnected bulk power system in North America. As part of this assessment, the program identifies and analyzes the impact of key issues and trends that may affect reliability in the future, such as market practices, industry developments, potential technical challenges, technology implications, and policy changes.

NERC reliability assessments are built on data supplied by users, owners, and operators of the bulk power system and gathered by the eight Regional Entities. This "bottom up" approach ensures that local and Regional issues are accounted for and their relevance understood.

Each year, the Long-Term Reliability Assessment forms the basis for the NERC reference case. This reference case incorporates known policy and regulation changes expected to take effect throughout the ten-year timeframe assuming a variety of factors such as economic growth, weather patterns, and system equipment behavior. A set of scenarios can then be developed from risk assessment of emerging reliability issues. These scenarios can then be compared to the reference case to measure and identify any significant changes to the bulk power system that may be required to maintain reliability.

For this reason, NERC investigated each of these issues through structured technical committees and leveraged the expertise of the electric industry's broad knowledge base. As a result, a series of reports were produced in 2010, exemplifying the industry's commitment to understand, resolve, and make recommendations that support enhancing future reliability (see Figure 27).

Figure 27: 2010 Special Reliability Assessments and Reports



2009 Emerging and Standing Reliability Issues Update

In 2009, NERC identified a number of significant emerging reliability issues that the electric industry will be challenged with over the next ten-years and beyond. The confluence of these issues may drive a transformational change for the industry, potentially resulting in a dramatically different resource mix, a new global market for GHG emissions trading, a new model for customer interaction with their utility, and a new risk framework built to address growing cyber security concerns, all with the underlying regulatory, legislative, and customer behavior uncertainty. Each of these elements of change is critically interdependent and industry action must be closely coordinated to ensure reliability.

Table 6 and 7 below detail the 2009 Emerging and Standing Issues identified by the Planning Committee and the progress that has been made since the 2009 Long Term Reliability Assessment. In addition, the chart also identifies which NERC committee has current ownership of each emerging issue.

Table 6: 2009 Emerging Issues Update

Issue	Progress since 2009 LTRA	Group Assigned
Economic Recession • Demand Uncertainty • Demand Response and Energy Efficiency • Rapid Demand Growth after Flat Period • Infrastructure Impacts	Demand uncertainty and rapid demand growth issues were addressed in the 2010 NERC report: *2010 Special Reliability Scenario Assessment: Potential Reliability Impacts of Swift Demand Growth After a Long-Term Recession* The issue has continued in 2010 and is a key highlight in this assessment.	Reliability Assessments Subcommittee
Transmission Siting	NERC continues to monitor the situation for any changes that would affect bulk power system reliability. In 2010, NERC collected data to support causes in delayed transmission projects	Reliability Assessments Subcommittee
Energy Storage	This issue was addressed in the 2010 NERC Report: *Reliability Impacts of Climate Change Initiatives: Technology Assessment and Scenario Development*	Reliability Assessments Subcommittee
Workforce Issues	This issue has been monitored by the IEEE Power and Energy Society under the topic of Workforce Collaborative in coordination with NERC	NERC Staff
Cyber Security	This issue has been explored in further detail in the 2010 NERC/DOE report: *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*. Additionally, the NERC management and multiple NERC committees are involved in researching further actions for the industry to take. Cyber security is discussed in the NERC report *Reliability Considerations for Smart Grid.*	Critical Infrastructure Protection Committee and Smart Grid Task Force

Table 7: 2009 Standing Issues Update		
Issue	**Progress since 2009 LTRA**	**Group Assigned**
Variable Generation	Comprehensive reports addressing reliability impacts of integrating variable generation continue to be developed. The following reports were published in 2010: • Special Report: Flexibility Requirements and Potential Metrics for Variable Generation and their Implications on Planning Studies • Special Report: Standard Models for Variable Generation • Special Report: Variable Generation Power Forecasting for Operations Additional reports are expected in 2011 including: • Special Report: Potential Reliability Impacts of Emerging Flexible Resources • Special Report: Ancillary Services and Balancing Solutions • Special Report: Accurate Methods to Model and Calculate Capacity of Variable Generation for Resource Adequacy Planning • Special Report: Reliability Impacts of Distributed Resources • Special Report: Enhanced Interconnection Requirements	Integration of Variable Generation Task Force
Greenhouse Gas Legislation	2010 NERC Report: *Reliability Impacts of Climate Change Initiatives: Technology Assessment and Scenario Development*	Reliability Assessments Subcommittee
Reactive Power	2009 NERC TIS Whitepaper *Reactive Support and Control*	Transmission Issues Subcommittee
Smart Grid and AMI	Report produced by the Smart Grid Task Force addressing the range of potential reliability impacts from wide-scale deployment of Smart Grid devices and systems	Smart Grid Task Force

2010 Emerging Reliability Issues Risk Assessment

Risk assessment of standing and emerging issues measures their perceived likelihood and potential consequences. To qualify for consideration, emerging issues must affect bulk power system reliability based on the following criteria:

1) Exists for more than a single year in the ten-year study
2) Impacts reliability no sooner than three years into the future to allow for sufficient assessment
3) Impacts reliability across at least one Regional Entity footprint and is not a local or subregional reliability issue.

During the June 15-16, 2010 Planning Committee meeting, the committee reviewed and approved Emerging Reliability Issues for review and further analysis by NERC in this assessment. A risk assessment was performed on these issues and described in the next section.

Risk Assessment

After the Planning Committee endorsed the Emerging Issues identified by three of its subcommittees (Transmission Issues, Resource Issues, and Reliability Assessment), the full Planning Committee prioritized the resulting issues based on risk, defined as their likelihood and consequence, and categorized each issue as high, medium, or low. This risk assessment was evaluated for two timeframes: the risk to the bulk power system in the next 1 to 5 years, and the risk to the bulk power system in the next 6 to 10 years.

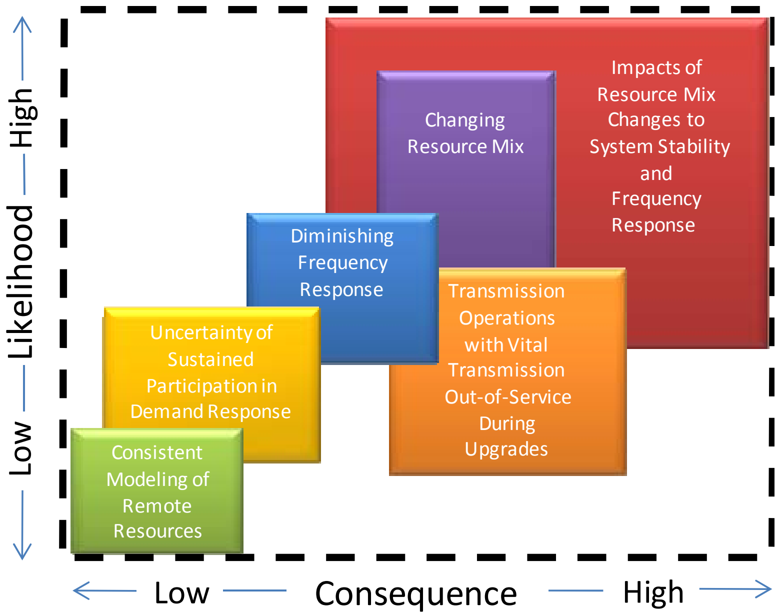
NERC's Reliability Assessment Subcommittee (RAS), Resource Issues Subcommittee (RIS), and Transmission Issues Subcommittee (TIS), with input from NERC Staff, identified six issues for use in the 2010 Planning Committee Risk Assessment. The issues are as following:

- Impacts of Resource Mix Changes to System Stability and Frequency Response
- Changing Resource Mix
- Diminishing Frequency Response (in the Eastern Interconnection)
- Transmission Operations with Vital Transmission Out-of-Service During Upgrades
- Uncertainty of Sustained Participation in Demand Response Programs
- Consistent Modeling of Remote Resources

Ranking and Risk Evolution

The risk assessment survey was completed by industry stakeholders represented on the NERC Planning Committee during the summer of 2010. Figure 28 provides the risk vectors for each of the emerging reliability issues for both the one to five (1-5) year and six to ten (6-10) year timeframes. Risk vectors for the 1-5 year timeframe are represented in the lower-left point of each rectangle—the 6-10 year risk vectors are represented in the upper-right point of each rectangle. With this perspective, relative risk of each issue is determined based on the Planning Committee survey results.

Figure 28: Emerging Reliability Issues
1-5 Years to 6-10 Years



In Figure 28, larger rectangles indicate significant risk change from the 1-5 to 6-10 year timeframes. Issues identified in the upper-right quadrant of the figure are considered high-likelihood and high-consequence to reliability. The *Impacts of Resource Mix Changes to System Stability and Frequency Response* issue risk assessment shifts the most between the 1-5 and 6-10 time periods, reflecting increased concern in the long-term. This issue has been identified as having the highest likelihood with the greatest consequence impacting reliability.

The *Consistent Modeling of Remote Resources* and *Uncertainty of Sustained Participation in Demand Response* reliability issues both ranked in the low-likelihood and low-consequence quadrant. While these issues are seen as having little risk to overall bulk system reliability, some concerns still exist in certain areas of North America.

The *Changing Resource Mix* shifts the most between the 1-5 and 6-10 time periods for likelihood only. This reflects the industry's belief that while during the short-term, solutions, approaches, and best practices are being developed, significant challenges exist in the long-term that must be overcome.

In summary, the ranking of the 2010 Emerging issues suggest the industry is being asked to solve many multifaceted, interconnected issues, while at the same time providing reliable service to its customers. The industry is in transformation, where many interrelated issues present complex risks to bulk power system reliability across the planning, design, and operational spectrum. Overall, the risk assessment suggests more than the relative importance of individual issues, but the confluence of the interrelated issues emerging simultaneously.

Impacts of Resource Mix Changes to System Stability and Frequency Response

System Stability is a measure of a synchronized power system's ability to regain a state of operating equilibrium after being subjected to an electrical disturbance. Frequency Response is a measure of an interconnected power system's ability to stabilize its frequency immediately following a sudden loss of a large - generating unit or units or a rapid change in load. The concern that frequency response is declining and monitoring this decline to ensure that reliability is not threatened has been an ongoing consideration over the last two decades. A number of studies have concluded that the decline in frequency response primarily stems from changes in the way fossil and nuclear-powered units are being operated to meet environmental and business goals along with reduced response from motor-driven loads.[44]

Strengths
- Early identification of the problem
- Diversified resource portfolio

Weaknesses
- Resource mix will continue to change
- Ability to restore integrity of system following a disturbance event

Time Horizon: 5 to 10 Years

Opportunities
- Change resource mix without diminishing System Stability and Frequency Response
- Lessons-learned can be developed through experience
- Support NERC Frequency Response Initiative

Threats
- Timing of Renewable Portfolio Standards and other emission reducing targets
- Incorrect modeling assumptions can lead to unexpected operating characteristics

Discussion

The Eastern Interconnection frequency governing characteristic has been tracked for over 25 years[45,46,47] One measurement of an interconnection Frequency Response, expressed in terms of MW/mHz, has steadily declined from 37.5 in 1994 to 25.4 in 2009.

Two of the primary factors affecting the frequency response of the power system are how the governors on these generators are being set and generator operation. When there is a frequency disturbance on

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[44] J. Ingleson and M. Nagle, 1999, *Decline of Eastern Interconnection Frequency Response*, Fault and Disturbance Conference at Georgia Tech, May 3-4,

J. Ingleson and D. Ellis, 2005, *Tracking the Eastern Interconnection Frequency Governing Characteristic*, IEEE,

NERC, 2004, *Frequency Response Standard Whitepaper*, Prepared by the Frequency Task Force of the NERC Resources Subcommittee, April 6

[45] James W. Ingleson and Eric Allen, "Tracking the Eastern Interconnection Frequency Governing Characteristic," Proceeding of 2010 IEEE/PES General Meeting, Minneapolis, MN, July 2010.

[46] Eric Allen, James W. Ingleson and Richard P. Schulz, "Monitored Unit and System Governing Response to Large Frequency Changes following Loss of Generation in Normal Operation System," Proceeding of 2007 IEEE/PES General Meeting, June 2007.

[47] NERC Resources Subcommittee, "Balancing and Frequency Control," Section on Frequency Response Trends, Page 14, July 5, 2009.

the system, governors sense a change in speed and adjust the energy input to generators' prime movers. Studies have concluded that the decline in frequency response could be due to steam turbine generators operating with:

- "Sliding pressure" or "boiler-follower" control
- "Valves wide-open" (VWO) operation
- Blocked governors
- Larger proportion of combined cycle units operating in "temperature control" mode[48]

Thus, changes in the relative share of the generation mix among the conventional generation resources (coal, gas, and nuclear) that make up approximately 90% of the North American generation mix as well as changes in how existing plants are being operated can both have a major impact on frequency response. An additional factor is the potential decline in response from motor-driven loads as their share of the total load has decreased, and the use of adjustable-speed drives increases.

Notably, this decline in frequency response has occurred prior to the rapid growth in the installation of variable energy resources, such as wind, occurring over the last five years (see companion emerging issue, entitled *Diminishing Frequency Response (in the Eastern Interconnection)*). Currently, variable energy resources comprise around 2% of the current installed generation mix, and the addition of wind energy has not been responsible for the observed decline in frequency response during the past two decades.

Early installations of wind turbines were not designed to provide frequency response, as they were generally small plants, with little interconnection impacts. Modern wind and solar generating plants can provide fast and accurate frequency response when solid-state power controls are added. Like conventional generators, variable energy resources will not provide sustained response to low frequency unless they are deliberately operated below their full output capability (to provide ancillary services or to match existing bulk power system energy needs) during normal operation.

Another factor influencing the stability of the system is the inertia of the generators connected to the system. Traditionally, the majority of generation has been from synchronous generators, which have significant inertia constants. Gas-fired generation, which has made up the largest share of new generation additions in recent years, consists of synchronous generators with inertia constants similar to the traditional generation on the system. In the past few years, variable energy resources, such as wind and solar, have been increasingly interconnected to the bulk power system, and projections indicated these interconnections, especially for wind and solar generation, are expect to increase significantly. As wind and solar generation do not deploy synchronous generators, they have smaller inertia constants relative to other types of generation.[49,50]

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[48] Frequency Task Force of the NERC Resources Subcommittee, "Frequency Response Standard Whitepaper," April, 2004.

[49] German Tarnowski, Philip Kjaer, Poul Sorensen, Jacob Ostergaard, *Study on Variable Speed Wind Turbines Capability for Frequency Response*, EWEC 2009.

[50] Vladimir Terzija, Mustafa Kayikci, Deyu Cai, *Power Imbalance Estimation in Distribution Networks With Renewable Energy Resources*, CIRED2009 Session 4 Paper No 0680.

Type III and IV wind turbines, which are expected to make up the majority of new wind turbine installations in the future, can have the capability to provide synthetic short-duration inertial response. Namely, this capability can increase output during the most critical first few seconds following a disturbance, while, at the same time, the individual turbines are not required to operate below their full output during normal operation. Wind generators with synthetic inertia can also support bulk power system stability as that response can be tailored to the power system's specific needs."[51] Therefore, the addition of large amounts of variable energy resources along with the retirement of coal generation can have either a negative or positive impact to the stability of the system. As with the additional of any sizable plant, interconnection simulations/studies need how to identify frequency and inertial response requirements, and how these will be obtained (*i.e.* interconnection standards, market rules, etc.). Further, to arrest the decline in the current bulk power system frequency response, appropriate actions will be required with existing and new plants to ensure that they support bulk power system reliability goals.

An additional factor that deserves further study is that variable energy resources tend to be located in remote areas of the grid, which may be a weaker part of the transmission system. As with remotely located conventional plants, when energy must be transported over longer distances to load centers, system stability must be simulated and appropriate actions taken to fortify the system and maintain bulk power system reliability.

Study methods and assumptions for conducting dynamic simulations may need to change with a resource mix change. Variable energy resources can involve converting electrical power from DC to AC by using power electronics. Some resources, such as wind generation, use induction generators combined with power electronics (*e.g.*, Type III – Doubly-fed asynchronous generator, and Type IV). Similarly, variable energy resources from solar-photovoltaic generation use power electronics to convert DC to AC. The accurate modeling of these new resources, similar to other existing resources, is very important in conducting stability simulations of the system. Due to the characteristics of most variable resources, such as smaller size, lower contingency reserve requirements, variability and uncertainty of output, assumptions on ramping and reserves become more crucial for system studies. The impact of these issues can vary with the load level of the system. Off-peak periods could require additional study due to variable generation potentially being a higher percentage of total generation. In addition, wind and solar resources can cause additional up-ward frequency response capability (response to a frequency drop) to become available on the generators they are displacing, as they cause units to be turned down from their maximum output. These issues should be addressed when assessing the impact of wind and other variable resources on the frequency response of the system.

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[51] NERC's 2009 report *Accommodating High Levels of Variable Generation*, concluded Type III and IV wind turbines, with their advanced power electronics, "can provide comparable inertial response/performance to a conventional generator." See http://www.nerc.com/files/Special%20Report%20-%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf, page 18.

RECOMMENDATION

In conjunction with the companion emerging issue, titled *Diminishing Frequency Response (in the Eastern Interconnection),* this issue should be studied comprehensively and specifically address:

- The industry should support the NERC Frequency Response Initiative and the development of enhanced interconnection standards
- Improving the models related to all generators, including variable energy resources, so that accurate system study results can be obtained.
- Investigating the methods and assumptions used for conducting dynamic simulations.
- Conduct studies to assess the effect on bulk power system stability and Frequency Response of the projected resource mix.
- Investigate other operational requirements of the projected resource mix, such as flexibility requirements, ancillary services, etc.

Changing Resource Mix

The capacity of the current resource mix is close to one million-megawatts (MW). Meeting carbon dioxide (CO_2) and other emission reduction targets will require a significant change in this resource mix as industry reduces the use of fossil fuels. Importantly, the pace and aggressiveness of emission targets will affect the options available for this evolution. This evolution in resource mix will require time so industry can gain experience with technology behavior, operating characteristics, and optimal planning approaches.

Strengths

- Larger, more diverse resource portfolio
- Integration of new baseload nuclear generation
- Increased fuel security

Weaknesses

- Inherent operating characteristics
- Variability and availability of renewable resources
- Decrease in frequency response and system stability

Time Horizon: 3 to 10 Years

Opportunities

- Maintain reliability while meeting future emmision targets
- Lessons-learned can be developed through experience
- Leverage virtually unlimited renewable energy sources

Threats

- Abnormal operations with unforseen consequences due
- Little experience with larger porfolio of variable resources
- Emission reduction target timing

The Reliability Assessments Subcommittee identified the following assumptions while reviewing this issue for consideration in the 2010 Emerging Reliability Issues assessment:

- A continued change in fuel resource mix is forecast to occur during the next ten years.
- Significant changes in the resource mix to occur due to fuel costs, incentives for variable generation, introduction of renewable portfolio standards, increased emission monitoring and regulation, and the addition of new nuclear resources to the generation portfolio.

The Table below details the resource mix changes based on existing and future capacity (Anticipated Resources) from 2010 through 2019. This table has been formulated based on the 2010 expected on-peak capacity projections.

Fuel-Type	2010	2019 Projected
Coal	31%	26%
Gas	29%	30%
Nuclear	11%	12%
Hydro	13%	9%
Renewables	1%	5%
Dual Fuel	11%	13%
Other[52]	4%	5%
Total	100%	100%

[52] Oil, other petroleum, pumped storage, other atorage, and undetermined energy sources are included

In addition, climate change initiatives and other emission reduction regulations could accelerate the retirement of many fossil plants beyond current projections, especially smaller, older, and less efficient coal plants, which are responsible for much of the load-following, voltage support, and other ancillary services in parts of North America. The impact of retirement of these older and smaller coal units will differ across North America. The pace and aggressiveness of emission targets will affect the options available for resource transition. Depending on the magnitude of retirements, in aggregate this could present Regional or North American-wide reliability challenges depending on the timing and type of replacement capacity. Further, the reliability of the bulk power system could be impacted if the penetration of non-fossil generation and demand resources lags behind current forecasts. This evolution will require sufficient time and operating experience to ensure reliability of the bulk power system throughout the transition.

Reliability Considerations

The Table above indicates significant changes in Coal, Gas, Nuclear, and renewable fuel types, due to a number of factors during the next 10 years. Coal use continues to decline due, in part, to increasing regulatory costs and long lead times required for construction, which are projected to make coal-fired generation plant operation less economical and their construction less certain. Reliability considerations associated with accelerated retirements of fossil fuel generation include the construction of new, low-carbon generation; new or upgraded transmission; penetration of Demand-Side Management; integration of variable resources; deployment of carbon capture and sequestration (CCS); cyber implications of smart grids; and the construction of a large number of nuclear plants. New transmission facilities will be needed to unlock new renewable resources and access to ancillary resources but will be constrained by regulations governing the siting of resources. With this resource mix shift, the dynamic character of the system will change as well (a subject of a companion issue, titled "*Impacts of Resource Mix Changes on System Stability and Frequency Response"*). Five resources areas will have significant impacts: variable energy resources, gas-fired generation, demand-side management, nuclear, and bulk power storage.[53]

Variable Energy Resources

State and Provincial governments have introduced renewable portfolio standards, which mandate organizations to procure specific amounts of energy from renewable sources, such as wind, hydro, or solar. Wind and solar generation are two of the most prevalent new alternatives to fossil-fired generation experiencing significant growth over the past several years. A recent NERC report projected over 200 GW of proposed and Conceptual wind and solar plants over the coming ten years. Though much of this may not be ultimately built, the figures are indicative of a substantial change in new resource development in the coming decade.[54]

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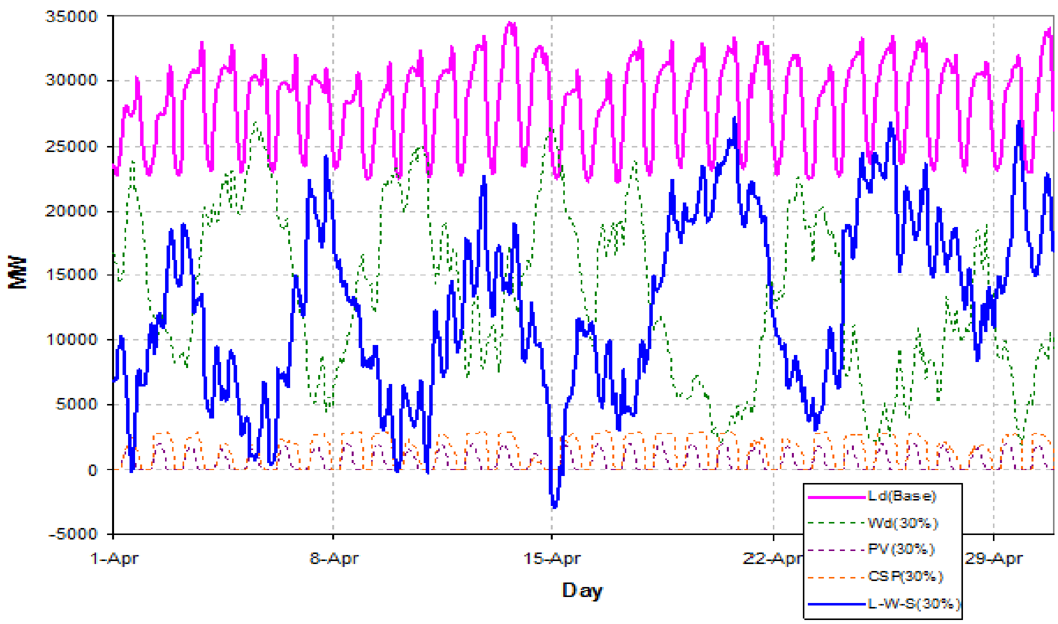
[53] See http://www.nerc.com/files/RICCI_2010.pdf for more detail

[54] http://www.nerc.com/files/2009_LTRA.pdf

Resources such as wind and solar are designated as "variable" due to the changing availability of their primary fuel source. While solar power correlates more closely to load patterns, wind power can often reach its peak output during times of relatively low demand for electricity. As neither resource can be sufficiently stored at a large scale at this time, this creates significant challenges for grid operators as they seek to keep the system in balance (see Figures 29 and 30).

According to NERC's 2009 Special Reliability Assessment,[55] there are two major attributes of variable generation that affect bulk power system planning and operations. The first is variability of plant output, as the primary fuel is not delivered in the same consistent fashion as coal, gas, or uranium. Rather, the output of variable generation changes according to the availability of the fuel, whether it is wind, sunlight, or moving water. The second is uncertainty in forecasting the timing of plant output. Together, these attributes demonstrate potential challenges to integrating variable resources at scale. Due to its limited availability during times of peak demand, wind power provides limited capacity and high volumes of "energy-dominant" resources (or those resources predominately available during off-peak hours). Further, integration of storage facilities, such as pumped hydro, can support conversion of this energy into capacity, as stored energy from variable resources can be dispatched at time of daily, weekly, or monthly peaks. Integrating large amounts of these resources, therefore, will require significant changes to traditional planning and operating techniques.

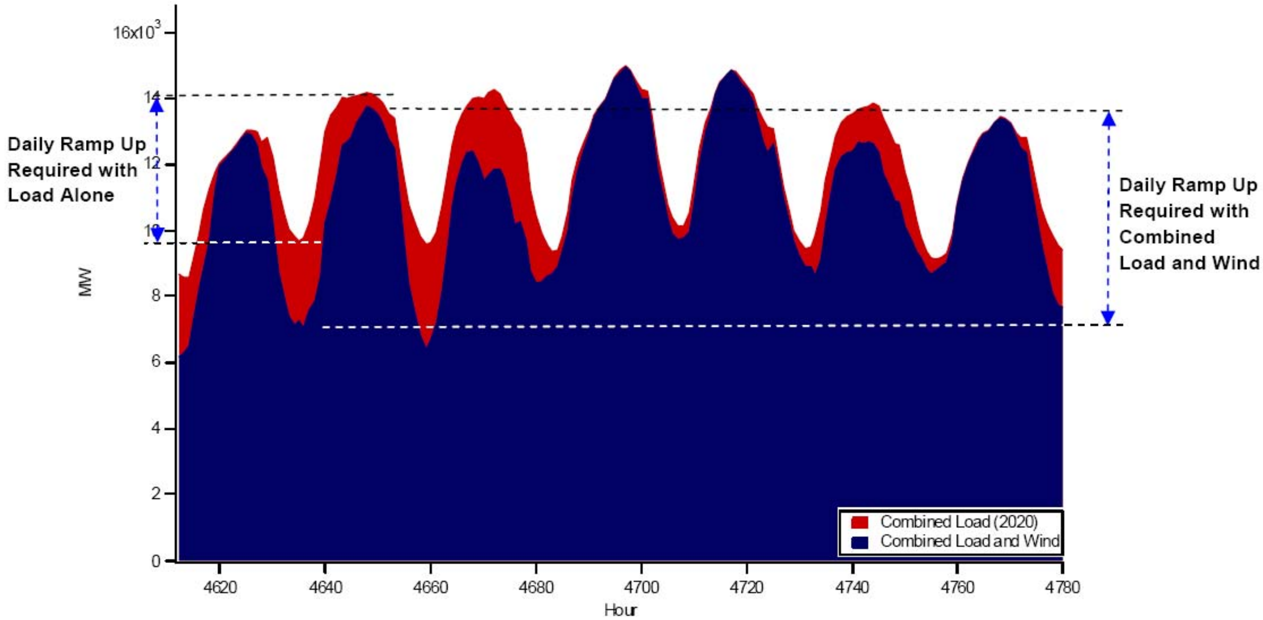
Figure 29: Total Load, Wind and Solar Variation for April (30% in Area Scenario)[56]



[55] NERC Special Reliability Assessment, "*Accommodating High Levels of Variable Generation*," April 2009, http://www.nerc.com/files/IVGTF_Report_041609.pdf

[56] Western Wind and Solar Integration Study DOE/GE Energy Study Impacts

Figure 30: Increased dispatchable ramping capability required with wind generation[57]



An additional challenge often associated with large-scale wind- and solar developments is that the best sites are located in remote areas, without sufficient supporting infrastructure.[58] Bulk power system planners must ensure there are sufficient transmission, distribution, and flexible resources available to unlock the energy resources and manage variability. This could be accomplished in the near term with Demand Response; larger, virtual/actual balancing areas; sufficient transmission; improved forecasting and scheduling tools; coordination with new or existing pumped storage hydropower; and diversity of plant locations designed to provide access to ancillary services. Sufficient transmission and/or energy storage capacity will be required to support variable generation integration. If transmission capacity or grid-scale storage is not available for transactions, variable resources may be curtailed after conventional resources are reduced to their minimum outputs. Curtailment of steam units would cause operational reliability concerns over the short term, as they would not be able to be returned to service when wind becomes unavailable. Furthermore, repeated cycling of steam units can cause reliability

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[57] If conventional generation resources are assumed to provide all the ramping capability for the system, the figure shows that, in the absence of wind generation, these conventional resources must be able to ramp from 9,600 MW to 14,100 MW (4,500 MW of ramping capability) to meet the VAriation in demand during the day, as shown in the figure by the red curve. With the additional wind generation, the VAriation in net demand, defined as the load minus wind generation, must be met using the ramping capability from the same conventional generators on the system. As shown in the Figure, wind generation is significantly higher during the off-peak load period than during the peak load period. Hence, the net demand during the day, shown in blue, VAries from 7,000 MW to 13,600 MW, requiring the conventional generators to ramp from 7,000 MW to 13,600 MW (6,600 MW of ramping), which is approximately 45 percent greater than the ramping capability needed without wind generation. See *Accommodating High Levels of Variable Generation,* NERC Special Report, April 2009, at http://www.nerc.com/files/IVGTF_Report_041609.pdf

[58] Western Governors' Association, *Renewable Energy Transmission Roadmap,* June 2010, http://www.westgov.org/index.php?option=com_joomdoc&task=doc_download&gid=1282

problems over the long term as the thermal stresses due to cycling will increase their maintenance requirements and potentially increase their forced outage rates, lowering the reliability of the system overall. Interconnection requirements for variable generation plants should support reliability of the bulk power system by providing sufficient voltage ride-through, frequency response, inertial response, and reactive support.

Large-scale deployment of photovoltaic (PV) technologies on customer rooftops could represent a significant change in the way that distribution system operates, which can affect the reliability of the bulk power system. Central grid-connected PV installations could have profound consequences given the frequent and severe ramping of output from PV that will require system operators and planners to allow for sufficient resources for system balancing and regulation (on a second-to-second and minute-to-minute time basis) to maintain system reliability.

In addition, large conventional plants have historically been operated at close to peak output continuously, while other generating plants could be cycled over the course of a day to meet varying demand. When variable generation sites are diversified or have capacity from persistent fuel sources, a portion of its installed capacity exhibits similar characteristics and capabilities as traditional generation. That said, variable generation integration is projected to require more operational flexibility. The future fleet of lower or non-carbon emitting resources must be designed to provide this capability. The following sections will provide more detail about the status of wind- and solar power.

Natural Gas-Fired Plant

On-peak capacity of natural gas-fired plant is projected to exceed coal-fired by 2011. Among the primary drivers are that natural gas generation plants are generally easier and faster to site, and have lower capital costs than other alternatives. Coupled with higher availability of unconventional natural gas supplies (*e.g.*, gas in shale formations, which represent up to two-thirds of North America's technically recoverable gas reserves[59]), developers could substantially increase gas-fired plant additions, changing the North American fuel mix while increasing the dependency on a single fuel type. In addition, with the addition of large amounts of variable generation (*e.g.*, wind and solar) low capacity-factor gas turbine plants may be required to manage increased system variability to meet reliability requirements.

As the bulk power system has been developed to support the delivery of energy from the existing generating fleet, sufficient time may be required to both site new gas-fired generation and reinforce the bulk power system.

Demand-Side Management (including Energy Efficiency and Demand Response)

DSM has led to reductions in supply-side and transmission requirements and supplements long-term planning reserves along with supporting operational reliability through the provision of ancillary services and overall system flexibility. It has also been used to manage the risk associated with construction and operations of traditional supply-side resources as well as a variety of new operating characteristics associated with variable renewable resources. For example, Energy Efficiency provides permanent

[59] *The Economist*, August 15–21, 2009, Pg. 24, *"The Economics of natural gas: Drowning in it"*

change to electricity use through replacement with more efficient end-use devices or more effective operation of existing devices. In many areas in North America, Demand Response, the other component of DSM, is also being used to support capacity requirements, energy requirements, and ancillary services.

Demand-Side Management (DSM) has been used for decades, leading to reductions in supply-side, transmission, and distribution requirements. DSM is an important part of the overall portfolio required to meet the electricity demand in North America and has two basic components: 1) Energy Efficiency (EE), and 2) Demand Response (DR). EE concentrates on end-use energy solutions and targets permanent reduction of electricity consumption, attempting to reduce the demand for power. Demand Response works to change the timing of energy use from peak to off-peak periods by transmitting changes in prices, load control signals, or other incentives to end-users to reflect existing production and delivery costs. Currently, DR penetration averages approximately six percent across all reliability Regions in the U.S.[60]

As Demand-Side Management (DSM) is increasingly deployed in response to climate change initiatives or mandates, it will become a larger portion of the overall resource portfolio. Climate change initiatives at the state/provincial level, along with consumer-led efforts to reduce energy consumption, will broaden the size and scope of DSM programs. Both Energy Efficiency and Demand Response can make significant contributions to the reduction in greenhouse gases, with Energy Efficiency providing ongoing benefits and Demand Response driving energy use to time periods when lower or non-carbon emitting resources are available. Demand Response can also enable the integration of renewable resources by supporting a variety of new operating characteristics associated with variable resources. Therefore, broader industry experience is needed, as the certainty, locality, and characteristics of DSM become increasingly important to reliability of the bulk power system

Reliability implications of large deployments of Demand Response resources are covered in a companion issue (*Uncertainty of Sustained Participation in Demand Response)*

Nuclear Plant

The current North American nuclear generation fleet is designed to provide continuous energy and capacity and little load following (regulating, ramping, cycling, starting/stopping, etc.), which is provided by smaller fossil-fired plants. Consequently, nuclear plants are generally run at close to peak output continuously, while fossil-fired plants may be cycled over the course of a day to meet demand. Variable energy resource integration will require more operational flexibility, which can be provided by demand-side resources and natural gas-fired plant. However, with the mid-range coal-fired units being replaced and the significant size of nuclear units (over 1,000 MW), the future fleet of nuclear plant may need to be designed to support overall flexibility of the power system to provide spinning reserves and ancillary services. Though this flexibility may be increasing somewhat with advanced designs, nuclear plants are generally not suited for cycling, and their high capital cost provides incentives for them to operate at the highest capacity factor possible.

[60] http://www.nerc.com/files/2009_LTRA.pdf

Requiring nuclear units to provide spinning reserves and ancillary services can make refueling periods less certain. Now, the predictability of refueling schedules can be forecast within hours. However, if ancillary services are provided, the complexity of scheduling refueling will increase.

Bulk Power Storage

Energy storage technologies are generally used to meet one of three categories. The first is providing continuity of service as generation is being switched from one source to another. In this application, the time period ranges from seconds to minutes. The second application is energy management. In this setting, storage devices are charged when energy demand is low, and discharged when demand is high. By providing capacity the storage unit can act as a load leveling device, increasing system efficiency. The third application is for ancillary services.

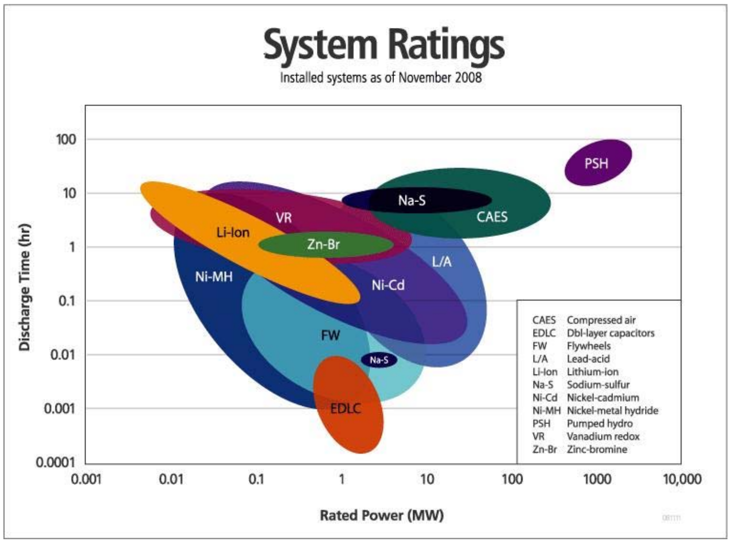
Energy storage technologies enable the decoupling of the instantaneous supply of energy from the variable nature of demand. This characteristic would enhance the integration of variable renewable resources into the grid and the provision of ancillary services (Figure 31). Other than water stored in existing hydroelectric systems, pumped storage hydropower is the most widespread energy storage system in use on power networks worldwide. Today, over 40 pumped storage projects operating in the United States and one in Canada, whose main applications are for energy management, frequency control, and provision of reserve, primarily spinning reserve, due to large turn-down ratios. Pumped hydro is available at almost any scale, with the largest operating plant capacity of just under 3,000 MW and with storage times ranging from several hours to a few days. Response time from speed no load to full power can be less than five seconds. Pumped storage plants are characterized by low operating costs and a 50- to 100-year life, but also long construction times and high capital expenditure.[61]

Storing energy during conditions when it is available, such as low-load periods, could provide additional resources for capacity, energy, or ancillary services. For example, energy storage resources could be used to serve peak loads as a dispatch-capable resource, making energy storage a viable way to manage generation minimums and provide additional capacity.

Depending on the energy storage device, it could maintain voltage and frequency as backup generation comes on-line, or provide sustained capacity when wind becomes unavailable. Second, energy storage can be used to provide ancillary services such as spinning reserves and frequency regulation. For example, when an energy storage device is used as a spinning reserve, the overall efficiency of the power system is increased. Third, storage can transform energy into capacity by storing available energy when demand is low and making it available when demand increases. This is especially helpful for variable generators that are available to counter daily peaks, such as wind generation. Parenthetically, pumped hydro has been used extensively to support nuclear plant installations, and provides grid-scale storage around the world.

[61] http://www.electricitystorage.org/ESA/technologies/pumped_hydro/

Figure 31: Comparison of Energy Storage Technology Characteristics[62]



Other than pumped hydro storage, to date widespread use of energy storage technologies on the bulk power system has been cost-prohibitive and therefore had minimal penetration. However, storage has been used in commercial and industrial facilities, especially to serve critical loads such as server plants and data centers. A number of prototype storage technologies are being tested throughout North America. For example, sodium-sulfur (NaS) batteries appear to be both compact and long lasting.

Compressed air energy storage (CAES), first tested at Alabama Electric Cooperative (PowerSouth Cooperative), is being considered by the Iowa Stored Energy Park[63] as a way to collect wind energy by storing compressed air in caverns below ground.

Flywheel technologies are also being deployed to supply electricity for brief periods—from a few seconds to a few minutes—to help support ride-through for sensitive loads.[64]

Cost-effective energy storage would improve overall system reliability because stored energy can replace or augment generation capacity at times of high demand. Thus, electricity providers could manage variable renewable resources needed to meet RPS requirements or nuclear plants with deployments of energy storage. Additionally, energy storage would improve frequency regulation and

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[62] Energy Storage Association, http://www.electricitystorage.org/ESA/technologies/technology_comparisons/

[63] http://www.isepa.com/

[64] The CIGRE (*Conseil International des Grands Réseaux Électriques* or International Council on Large Electric Systems) Study Committee C6, "Distribution Systems and Dispersed Generation" has recently initiated Working Group C6.15, entitled "Electric Energy Storage Systems," to evaluate different storage technologies and support their integration in power systems with high penetration of dispersed generation and renewable based generation.

local capacity reliability, and enable injection of power into the system when the electric grid experiences system disturbances or is facing stability issues.[65]

Accordingly, the electric industry is interested in the progression of energy storage technologies as a way to convert energy into capacity and as a way to provide ancillary services.

Planning and Operational Impacts

Overall system characteristics will be impacted by large shift in resources mix that must be modeled in a resource assessment. Understanding and modeling these changes is vital to ensure that the bulk power system provided to operators can be managed reliably.

Operators will need to gain experience and develop new operating procedures to effectively manage in a new operating environment. The base load environment will significant change requiring new procedures to be developed which ensure the reliable operation of the bulk power system. For example, system flexibility must be available to support variable energy resources and minimize limitations to existing resources.

Recommendation

- The characteristics of the projected bulk power system should continue to be studied more comprehensively to ensure that it meets NERC's Standards as well as provides sufficient flexibility and frequency response (see companion issue, titled "*Diminishing Frequency Response"*).

[65] "Energy Storage for Wind Integration, a Conceptual Roadmap for California," Carnegie Mellon Conference on the Electric Industry, March 10, 2008, Slide 5

Diminishing Frequency Response (in the Eastern Interconnection)

Frequency Response, a measure of an interconnection's ability to stabilize frequency immediately following the sudden loss of generation or load, is a critical component of to the reliable operation of the bulk power system, particularly during disturbances or restoration. There is evidence of continuing decline in Frequency Response in the Eastern Interconnection (also in the Western and ERCOT interconnections) over the past 10 years, but there are a combination of factors contributing to this decline.

Strengths

- Industry, regulators, and policymakers are aware of the situation
- Phenomena isolated primarily in Eastern Interconnection

Weaknesses

- Low frequency response will significantly effect system stability
- Ability to restore integrity of system following a disturbance event

Time Horizon: Immediate

Opportunities

- Develop incentives for providing frequency response
- Lessons-learned can be developed through experience
- Support NERC Frequency Response Initiative

Threats

- Diminishing trend continues
- Changes in resource mix contribute to diminishing trend
- Distubance event can lead to uncontrolled, cascading outages

The Reliability Assessments Subcommittee identified the following assumptions while reviewing this issue for consideration in the 2010 Emerging Reliability Issues assessment:

- Measurable reductions observed during disturbance events; downward trend is evident
- The NERC Frequency Response Initiative will provide a dataset which future research can be conducted against

Figure 32 is a typical trace following the trip of a large Generator in the Eastern Interconnection while Figure 33 is a comparable trace from ERCOT.[66] In the Eastern Interconnection graph, the lack of a frequency response is notable in both selected sections of the graph and indicative of a long-term problem in the Eastern Interconnection.

[66] These figures were extracted from the Balancing and Frequency Control Technical Whitepaper published by the NERC Resources Subcommittee on July 5, 2009. http://www.nerc.com/docs/oc/rfwg/NERC%20Balancing%20and%20Frequency%20Control%20July%205%202009.pdf

Figure 32:

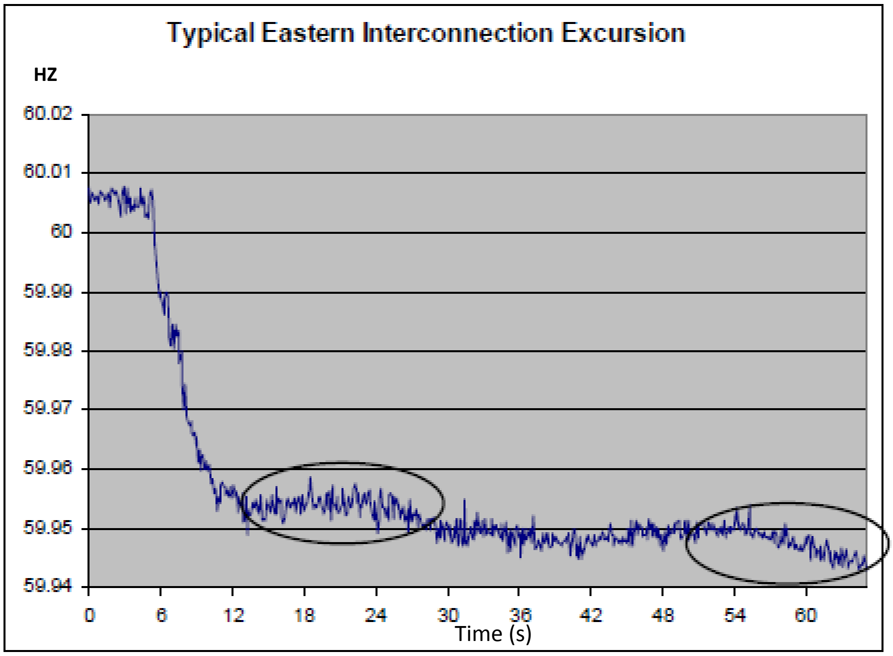
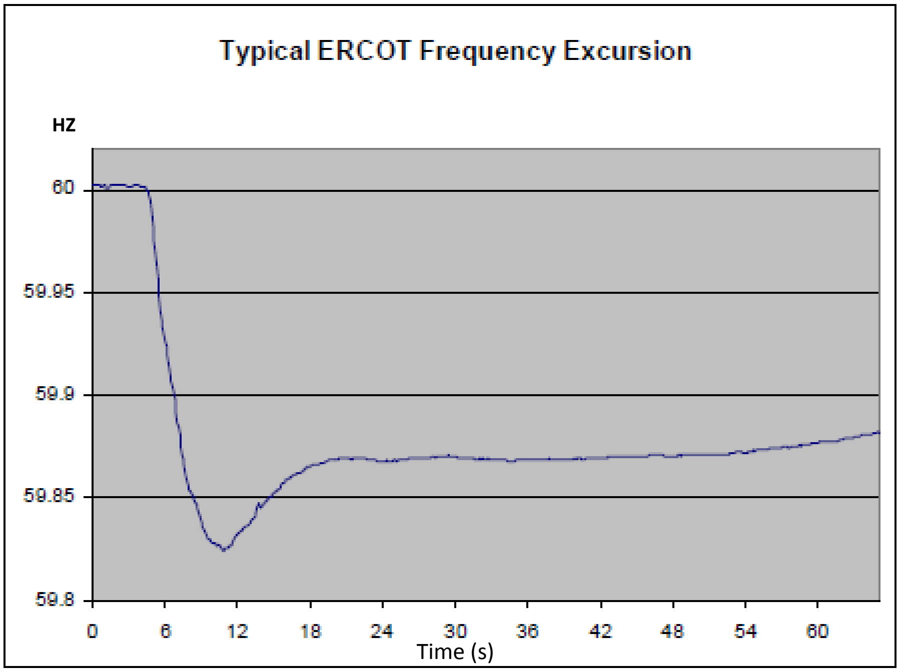


Figure 33:



A key concept of primary frequency response is that it will only stabilize the frequency of an Interconnection following a large generator trip. With primary frequency response, a generating unit will respond to frequency excursions by adjusting load in response to the frequency change in order to try to help maintain grid frequency. With secondary frequency response, frequency will not recover to pre-trip levels until the responsible Balancing Authority replaces lost generation through Automatic Generation Control (AGC) and reserve deployment of resources (remote frequency control).

Operational Impacts

The bulk power system is operated to ensure that the number of facilities able to meet a frequency decline will be online and ready to respond within a short period. This requires certain units to be brought online at uneconomical times to provide voltage support and response to frequency declines. With these additional units on-line, transmission lines may have to operate at transfer limits to meet frequency response initiative targets.

Planning Impacts

Planning and system models must be enhanced to incorporate frequency declines across the bulk power system and effective response procedures to such declines must be explored. Current modeling is insufficient to analyze the phenomenon. Sufficient responses to frequency declines may result in the need for access to additional ancillary services, which may further strain existing transmission networks.

Recommendations

- The industry should support the NERC Frequency Response Initiative[67], which is tasked with the following objectives:
    - Identify specific frequency-related reliability factors
    - Identify root causes of changes in frequency response
    - Identify practices and methods to address root causes
    - Consider impacts of integration of new generation (*e.g.*, wind, solar, and nuclear)
    - Share lessons learned with the industry
    - Determine if performance-based frequency response standards are warranted
- NERC should collect data to analyze current and historical frequency response performance and what factors influenced the observed performance.
- NERC should analyze what is the appropriate frequency response and control performance requirements, and establish minimum bias settings for use in AGC systems to maintain system reliability.

[67] http://www.nerc.com/filez/standards/Frequency_Response.html

Operations with Vital Transmission Out-of-Service During Upgrades

Transmission system expansion typically encourages operators because of the enhanced probability of future, less stressful operations. However, the short-term consequences of line outages and construction can create operational challenges. Stressed operations due to the need for planned outages and extended planned outages of transmission facilities while they are being upgraded is a concern experienced historically and recently across North America. These outages may cause abnormal operations, increased vulnerability, and possible resource deliverability and transmission constraint issues. While a majority of the impacts would be economic with generators being dispatched out of economic order, if all economic solutions have been exhausted reliability may become an issue.

Strengths
- Enhancing grid reliability with more robust and resilent transmission facilities
- Wide-area coordination improves industry communication and best-practices

Weaknesses
- Transmission line must come out-of-service in order to be upgraded
- Outage of critical transmission lines increase vulnerability

Time Horizon: Infinite

Opportunities
- Maintain reliability while performing upgrades
- Lessons-learned can be developed through experience
- Emergency re-energization plans should be developed

Threats
- Abnormal operations with unforseen consequences due
- Multiple contingencies
- Prolonged outage

The Reliability Assessments Subcommittee identified the following assumptions while reviewing this issue for consideration in the 2010 Emerging Reliability Issues assessment:

- This issue has occurred previously and it is anticipated to occur in the future in varying degrees.
- Significant bulk power transmission is planned for construction over the next five and next ten years

Operational Impacts

During facility upgrades, operations can be challenged by having bulk transmission elements, which were normally heavily loaded already, out-of-service. Operators would then be challenged to dispatch generation resources out of typical order to manage parallel transmission capacity issues. Transmission capacity issues can be compounded if lower voltage facilities are in the same right of way, require coincidental maintenance or upgrades, or are forced out-of-service.

Another challenge is coordinating critical 500 kV or greater line outages that can last four months, through the spring or fall. Prolonged outages are also possible past four months with the potential for multiple critical lines being out-of-service as well. The risk is intensified if higher than expected loads are experienced at the start and end of the outage as peak seasons are ending or beginning. For example, the prolonged outage of the Meadowbrook–Morrisville (TrAIL) 500 kV line required periodic meetings between operators and planners from Allegheny Power, TrAILCo, Dominion and PJM in advance of the outage to make sure the project started on time (as soon as the peak load season declined). Meetings were also required during the outage to ensure the project completed on time. Coordination included the creation of an Emergency Return Procedure in case high load was anticipated in the short-term.

PLANNING IMPACTS

The industry must plan to have transmission elements out-of-service and design appropriate contingencies to mitigate potential consequences of losing critical transmission facilities. Plans should recognize the possibility of the line outage being extended due to delays in construction. Because a higher-voltage transmission line is out-of-service, other normally less-critical transmission lines may become critical to reliability. Existing transmission facilities may need to operate at their system limits for the duration of construction. Plans to mitigate impacts and ensure the reliability of the bulk power system must be considered and coordinated across all affected entities. Possible delays in transmission capacity upgrades may require more in-depth study. Short-term topology or transmission configuration may require additional modeling. Modeling phases of construction may be required to fully capture the impact of upgrade-induced extended outages.

RECOMMENDATIONS

- To limit the operational impact of transmission upgrades, facility upgrades should be widely coordinated and communicated outside of the utility's operating area so any real-time operations impacts can be limited in advance.
- The industry should coordinate at both an intra-Regional, inter-Regional and local level to ensure appropriate plans are in place when transmission upgrades are considered and scheduled. Plans for emergency re-energization must be created. Earlier review of the physical considerations of the upgrade may need to be completed by planning personnel in coordination with construction crews.

UNCERTAINTY OF SUSTAINED PARTICIPATION IN DEMAND RESPONSE PROGRAMS

While many similarities exist between Demand Response and generating capacity, key differences in terms of availability, performance, and sustainability may appear as a given system becomes more stressed. Less understood attributes of these resources, such as response fatigue[68] *or economic-based participation rates, must be carefully monitored to assure they do not pose reliability issues in the future. Demand Response is increasingly being used to balance system load and relieve resource adequacy and transmission reliability issues. Decreased or insufficient participation could lead to operational challenges where peak demand is not able to be met by current generation or transmission resources.*

STRENGTHS	WEAKNESSES
•Participation is on the rise •Provides operators with fast-acting, flexible resources •Ability to aquire new resources relatively fast	•Suffers from response fatigue •Short commitment periods •Highly dependent on economics

Time Horizon: 3 to 10 Years

OPPORTUNITIES	THREATS
•Ability to aquire new resources relatively fast •Defers the need for additional generation •Provide ancillary services for variable generation	•Increased frequency of use may deter participants •Little experience with larger porfolio of resources •Long-term sustainability is uncertain

The Reliability Assessments Subcommittee identified the following assumptions while reviewing this issue for consideration in the 2010 Emerging Reliability Issues assessment:

- Demand Response participation plateaus in the long-term
- Potential increase in frequency of use within the short-term
- Character differences in traditional generation resources versus Demand Response resources

OPERATIONAL IMPACTS

The increased penetration of Demand Response raises operational challenges in numerous areas of day-to-day operation of the bulk power system. Should Demand Response be unable to deliver the required reduction in demand as committed, real-time operations may be challenged to ensure adequate resources are available (contingency reserve) and that transmission facilities are operated within their defined limits to maintain bulk power system reliability.

Any analysis of Demand Response fatigue should also attempt to determine whether measure type – *i.e.*, load reduction versus customer-owned generation or temperature-sensitive load versus non-

[68] Response fatigue is a characteristic of demand resources who initially participate in Demand-Side Management programs because of the financial incentives; however, once the electric supply to their equipment has actually been interrupted a number of times, the inconvenience outweighs the cost savings and may potentially withdraw from the programs.

temperature-sensitive load (*e.g.*, HVAC versus lighting, etc.) – plays a significant role in the issue of Demand Response fatigue.

Demand response fatigue issues also concern baseline estimation. The difference between the baseline and the resource's actual load is commonly used to determine the performance of a Demand Response resource. However, if a Demand Response resource is both responding to high-energy prices *and* is participating in a capacity market (jointly-enrolled participation), the resource will not be available to reduce load should Emergency Operating Procedures (EOPs) be invoked at a time when the Demand Response resource is actively reducing load for the price-responsive program. If the Demand Response resource is already reducing load when EOPs are called, the amount of load reduction available from those Demand Response resources could actually be lower than their capacity market obligation. This is especially an issue if the system operator is not aware that the load relief was unavailable. Additionally, if a Demand Response resource is responding often to price signals, it becomes unclear how the baseline should be estimated. Establishing a baseline method for Demand Response resources gives the system operator an accurate, real-time picture of available Demand Response.

In addition to baseline estimation issues, analysis should also include data quality and meter accuracy issues that have been encountered in estimating actual Demand Response reductions. Telemetry data provides effective and reliable metering solutions that provides near real-time meter information in order to assess actual performance. Follow-on action can then be taken by the system operator once the initial dispatch signals have been given. System operators must know how much Demand Response actually responded. Further, system operators may be able to track or identify actions by Demand Response resources through feeder, substation, or pricing node data.

These issues become even more important as system operators begin to use Demand Response to control transmission constraints and provide ancillary services and contingency reserves. Program-specific details to the maximum interruption frequency must be fully considered. For example, several Demand Response programs limit the amount of times service can be interrupted from the customer within a given time period (*e.g.*, per day, month, or season). Where these limits exist, reductions in peak demand may not be obtainable by the system operator if extreme weather conditions were to persist for a prolonged period of time during the peaking season. More experience and data analysis associated with Demand Response performance will be required to establish the long-term availability, effectiveness, and customer acceptance of these programs.[69]

PLANNING IMPACTS

The trend of increased use of Demand Response programs to meet projected peak demands gives system planners the confidence that the trend will continue in the future. If Demand Response programs fail to deliver promised load shedding, additional generation resources and transmission facilities may need to be planned and constructed to deal with an unplanned contingency response. Additionally, expected transmission and generation resources may not be online due to scheduled or

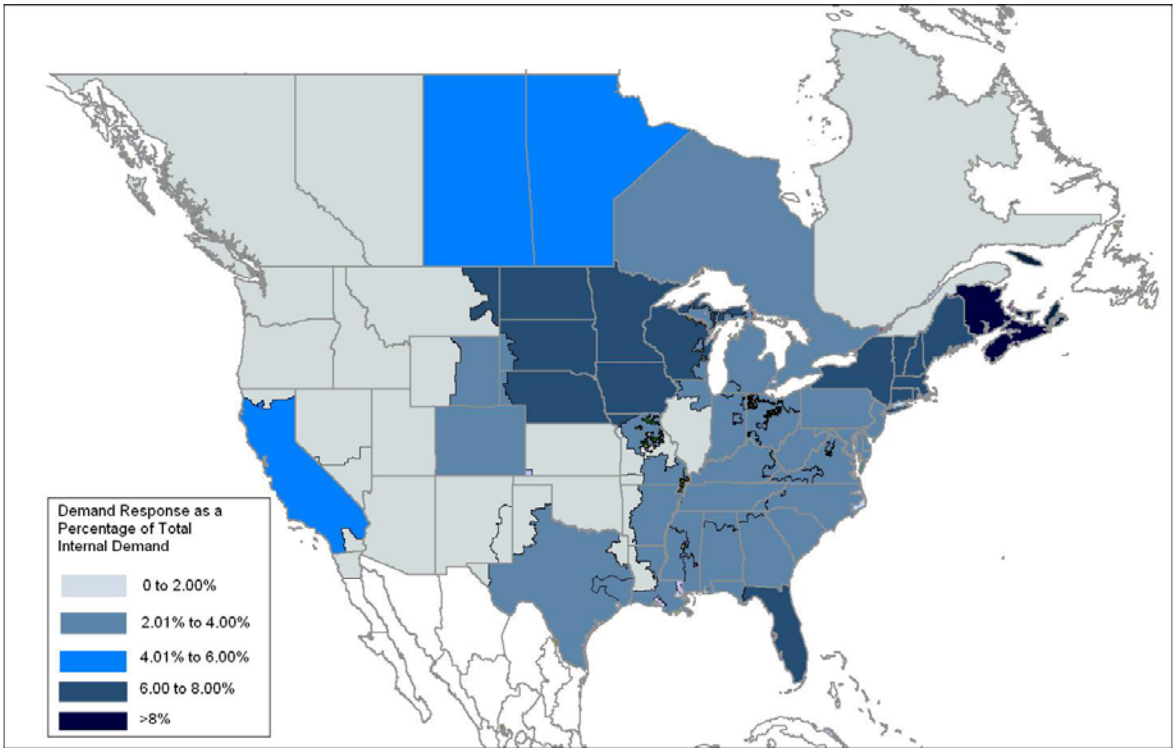
[69] The NERC Demand Response Availability Data System (DADS) is currently collecting (on a voluntary basis) historical Demand Response Performance Data. In 2012, data collection will be mandatory. For more information, visit the DADS website at : http://www.nerc.com/page.php?cid=4|357

unscheduled maintenance, further complicating the issue if Demand Response programs are planned as fixed reductions in load.

These results and findings of any analysis on Demand Response fatigue should assist system planners in developing guidelines for treatment of Demand Response resources within both short and long-term planning studies. The assumptions regarding performance and availability of Demand Response need to be developed and incorporated into various types of traditional transmission planning studies such as steady state, short circuit, thermal and voltage analyses.

While not all areas in North America are concerned with the sustainability of Demand Response currently, certain areas have a large percentage of their area's Total Internal Demand being met with Demand Response (see Figure 34). These areas are considered to be most susceptible to issues arising with decreased participation in the future.

Figure 34: Current Demand Response as a Percentage of Total Internal Demand Across North America



RECOMMENDATIONS

- NERC should monitor DADS data in the future to identify availability and/or performance trends that may indicate potential risks to the bulk power system.

Consistent Modeling of Remote Resources

The current focus of successful integration of renewable resources is the transmission of electrical power over long distances. These resources may travel over multiple balancing or planning authority areas. Coordination of transmission modeling with neighboring areas is currently an issue. Transmissions of more power over longer distances and across even more balancing and planning authorities will only exacerbate the problem and perhaps spread the problem into resource planning coordination.

Strengths

- Wide-area coordination improves industry communication and best-practices
- Interconnection-wide planning groups are established

Weaknesses

- Remote resources are not near demand areas
- Coordination is required across several entities
- Models are only as good as their assumptions

Time Horizon: Immediate

Opportunities

- Enhance tie benefits across systems
- More transmission provides increased access to more ancillary services and importing capability

Threats

- Incorrect modeling assumptions can lead to unexpected operating characteristics
- Differing model assumptions between two areas

The Resource Issues Subcommittee identified the following assumptions while reviewing this issue for consideration in the 2010 Emerging Reliability Issues assessment:

- Observable inconsistencies in model assumptions across the industry
- Operations and planning approaches do not significantly change during the next ten years

Operational Impacts

The transmission system must ensure reliable delivery of remote resources to demand areas. An operational study of tie-flows across balancing authorities has been started to determine the benefits available to entities that participate in these schemes. Additionally, real-time operations will need to consider whether plans have been made in advance to schedule power flow from distant resources during peak demand periods.

Planning Impacts

All firm users in the electrical path from the resource to the load may have to curtail their service if the generation and transmission system cannot support the import when requested. In addition, planned resources may not be deliverable from the source area due to system constraints at the requested time. Intervening areas will need to examine resource plans of recipient area when performing planning studies to ensure that cross-Region flow does not restrict use of internal resources. Contingency planning for line outages will also need to be accurately reflected in resource assessments to understand the impact on the bulk power system.

Recommendations

- The industry should continue addressing modeling issues through their respective interconnection-wide planning groups.

Bulk Power System Risk Index

Introduction

With modern technology and changing reliability requirements, virtually every complex system in the world, such as communication systems, computing systems and bulk power systems, needs an integrated risk management process in place. Risk assessment is an essential tool for achieving the alignment between organizations, people and technology in quantifying inherent risks, identifying where potential high risks exist, and evaluating where the most significant lowering of risks can be achieved. Being learning organizations, the Electric Reliability Organization (ERO) along with the Regional Entities and the Registered Entities can use this tool to focus on the areas of highest risk to reliability and provide a sound basis for developing results-based standards and compliance programs. This tool also serves to engage all stakeholders in a dialogue about specific risk factors, and helps direct a strategic plan for risk reduction and early detection.

Under the direction of the Operating Committee (OC) and Planning Committee (PC), the Reliability Metrics Working Group (RMWG)[70], has developed a concepts document[71] that includes:

1. A framework for developing and implementing a risk-based approach to assess reliability trends
2. Recommendations for identification and calculations of reliability measures and risk assessments, including risk-significant events and relative severity ranking of the events

Development of the tool is to investigate and evaluate disturbance history that can be useful in measuring the severity of these events. The relative ranking of events requires industry expertise, agreed-upon goals and engineering judgment. The final numerical ranking/scoring considers the NERC approved Adequate Level of Reliability[72] and existing Standards.

This chapter presents the framework and process for identifying risk-significant events and determining severity ranking of these events. Through this process, the industry can measure, monitor, and manage risks to bulk power system reliability. A baseline and a three-year average of severity curves are also included to illustrate how the results can be used to make risk-informed decisions.

It is important to note that this development is only in its Conceptual stage. Based upon feedback from stakeholders and periodic review, the risk assessment, including relative severity ranking will be refined and updated. No conclusions as to these severity curves can be drawn at this time.

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[70] The latest RMWG scope is available at http://www.nerc.com/docs/pc/rmwg/Reliability_Metrics_Working_Group_Scope_Final.pdf

[71] The whitepaper "Integrated Bulk Power System Risk Assessment Concepts" is available at http://www.nerc.com/docs/pc/rmwg/Draft_Integrated_Bulk_Power_System_Risk_Assessment_Tools_8-26.pdf

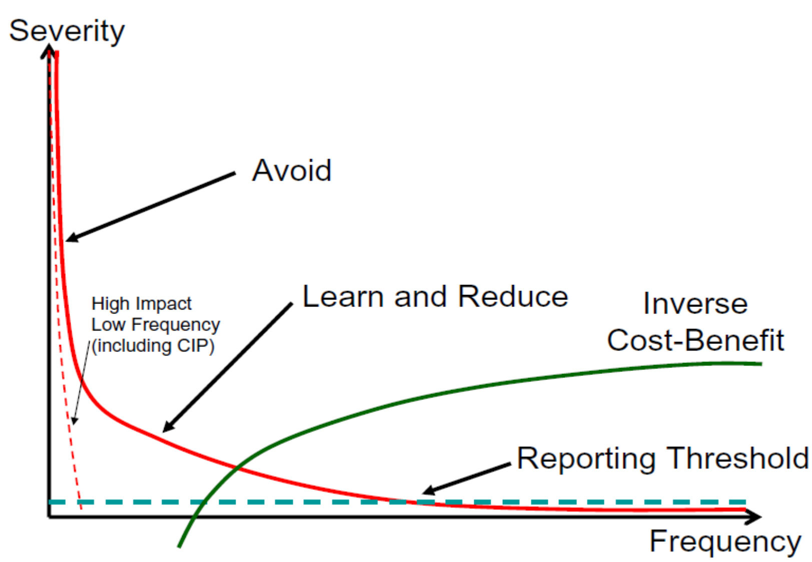
[72] Detailed definitions of ALR are available at http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf

Conceptual Model for Assessing Risk

Assessing and managing risk is a single continuous process that, if implemented consistently among bulk power system owners and operators, can be used to recognize and act upon the risk to the bulk power system from undesired potential performance shortfalls. One objective of managing risks is to decrease the probability of events that reduce bulk power system reliability. The recognition of acting upon reliability risks should evolve the industry towards a single continuous process. In the graph below, Figure 35, the red line depicts the events ranging from minor outages to very high-impact extreme events. There are events that occur with high frequency, but are quite small in terms of customer impact, as depicted in the blue line. Many bulk power system events have generally no impact (and may be considered off-normal events[73] or "operated as designed" type events) due, potentially in part, to the redundancy built in the bulk power system or other mitigating operations. Additionally important in Figure 1 is a line marked "Reporting Threshold", which is Conceptually a level below which the severity does not even warrant external reporting because the impact is low (or outside the jurisdiction of the regulatory framework) or the system has operated as designed (also resulting in limited impact).

Events of greater severity can be studied[74] along with the identification of overall trends as a way to manage risks associated with these events. The result would be to move the curve downward and to the right, reducing the severity and frequency of high-impact events, or eliminating them. The efficient processing of this information, to create a comprehensive rational and effective risk-mitigating and learning environment, is the challenge faced by system owners/operators, Regional Entities and NERC.

Figure 35: Cornerstone of Risk-Management Concepts

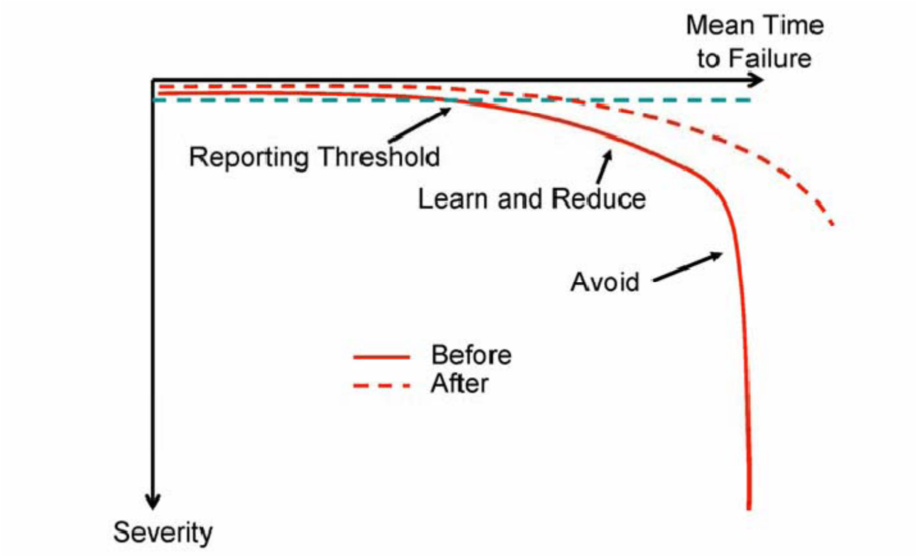


[73] More on off-normal events are available at NERC RoP Section 808 and can be viewed at http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20100205.pdf.

[74] For this purpose, NERC has created a categorization system to help filter those events which warrant more attention for learning purposes. See NERC website at: http://www.nerc.com/page.php?cid=5|252.

Figure 36 below changes the perspective. In addition to a reversal of the axis, the beneficial impact of reviewing events and applying knowledge is shown. By applying the risk assessment results to operations, there is the potential to extend the mean time to failure of a bulk power system facility and reduce the event's severity. This concept is the fundamental premise of any risk management effort.

Figure 36: Severity Reduction and Beneficial Impact



Historically, risk has been assessed by bulk power system planners by setting thresholds and safety margins so as to avoid "unacceptable" risk, where acceptability levels are typically determined by industry experience. For example, probabilistic models have been used by industry to build systems with sufficient generating capacity so that it would fail to meet demand no more than one day in ten years. Similarly, power system operation is governed largely by the "N-1 security criterion" which requires that the system, as a whole, can sustain failure of any one element (*e.g.*, generator, transmission line, transformer etc.).[75] However, operators regularly have to deal with multiple contingencies and multiple contingencies are considered in power system planning. Conceptually, these approaches represent an avoidance of risk, by use of deterministic criteria, rather than the management of risk, by use of probabilities of events with specific known severities.

Risk models refer to the use of quantitative or statistical methods to determine the aggregate risk based on a portfolio of individual risk factors. One of the fundamental statistical methods used widely among many industry sectors is regression analysis. Other techniques include Value-at-Risk (VaR), Historical Simulation (HS), Extreme Value Theory (EVT) or Scenario Analysis to assess a portfolio of risk categories. Formal risk modeling is also required by the various institution regulators, including the Federal Aviation Administration, the Nuclear Regulatory Commission, and the Food and Drug Administration. Many firms use risk modeling to help guide a strategic plan for risk reduction and early detection.

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[75] Oren, S., "Risk Management vs. Risk Avoidance in Power Systems Planning and Operation," IEEE-PES, 2007, http://www.ieor.berkeley.edu/~oren/pubs/II.B.10.pdf

Severity Risk Index

The risk assessment uses historical event data to develop a severity metric risk measurement and establish the bulk power system's characteristic performance curve. This curve would then be applied, prospectively to particular risk events, period performance assessments and provide groundwork for developing cost avoidance parameters. Further, a family of curves focused on structural (*i.e.* interconnection), components (*i.e.* generation, transmission, etc.) and trends evaluations (grouping events by causes) can be developed.

The severity of an event has a number of key characteristics, which are reflected in the ALR definition:

1) Number of bulk power system components forced out of service during the event
2) Unacceptable facility damage
3) Duration of event (hours)
4) Amount of demand (MW) lost during the event

Events are ranked by relative severity levels to quantify the impact. Impact can be along multiple dimensions such as load (as a proxy for customers) or loss of facilities (such as generators, transmission lines, substations or communications facilities). These measures provide a numerical ranking to determine which events are more important to maintaining system reliability. In other words, the metrics are an integrated risk measurement system, which classifies an event's impact.

At a high and generic level the Severity Risk Index (SRI) serves as an indicator of severity of the major impacts into one integrated measure. Relative weights, based on industry judgment, can be used to develop relative importance of each impact component. The value of the severity is calculated based on impact of risk-significant events and the relative weightings.

$$SRI_{event} = w_L*(MW_L) + w_T*(N_T) + w_G*(N_G)\ ) + w_D*(H_D) + w_E*(N_E)$$

Where:

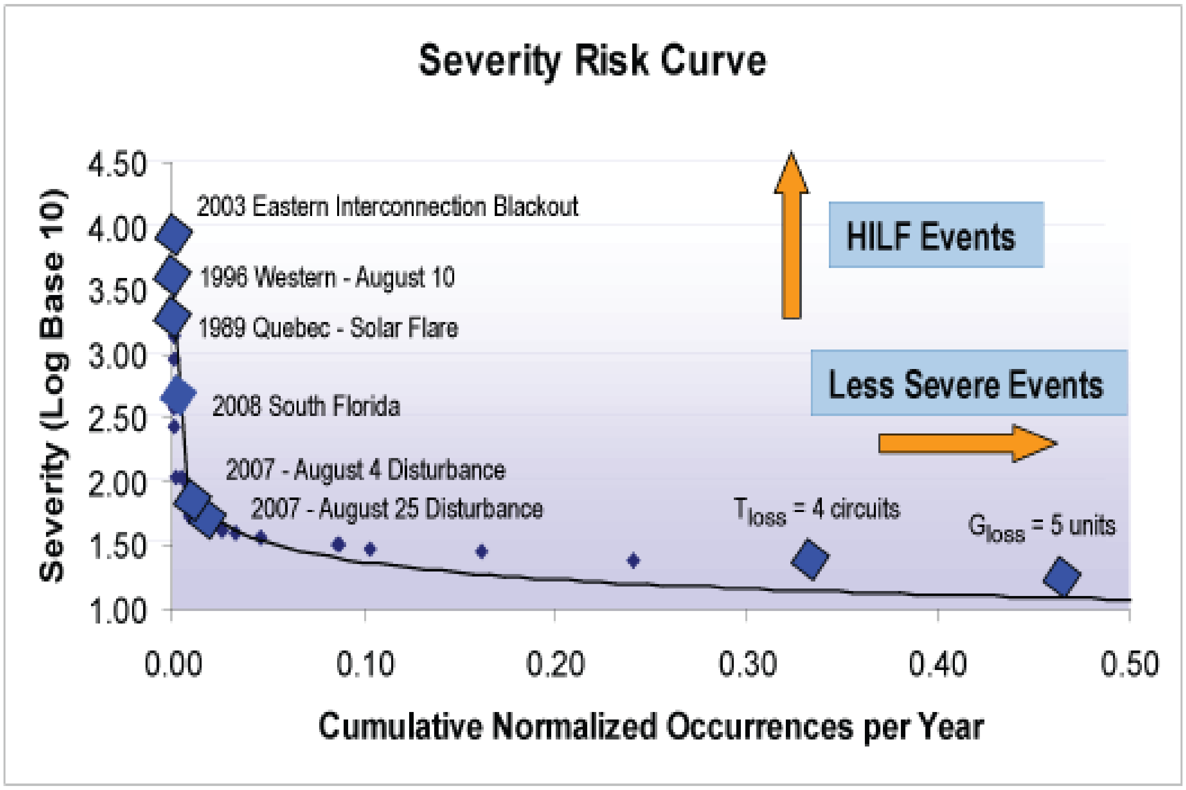
SRI_{event}	=	severity risk index for specified event,
w_L	=	weighting of load loss,
MW_L	=	normalized MW of Load Loss in percent,
w_T	=	weighting of transmission lines lost,
N_T	=	normalized number of transmission lines lost in percent,
w_G	=	weighting of generators lost,
N_G	=	normalized number of generators lost in percent
w_D	=	weighting of duration of event,
H_D	=	normalized duration of the event in percent,
w_E	=	weighting of equipment damage, and
N_E	=	normalized number of equipment damaged in percent

Based upon feedback from stakeholders and periodic review, these weighting factors will be refined and other factors that affect severity of a particular event will be considered. For example, equipment operated as designed and loss of load from a reliability perspective (intentional and controlled load shedding) could all be part of this consideration. Further, the process of enabling ongoing model update of the historic and simulated events for future severity risk calculations will be established.

Other aspects affecting weighting factors include differences between electrically remote facilities, which are out of service, and those in close proximity, which either initiate or propagate the effects of the event. Regarding generators, there could be some benefit derived by adding a factor for total capacity lost. In the load pocket areas where local voltage support is essential to maintain system stability, the generation loss in these areas will be weighted more.

Figure 37 provides a sample risk assessment graphic representation using the aforementioned SRI. The loss of load due to transmission-related events is weighted the highest (60%) since it directly indicates the unacceptable reliability level per ALR.6. The transmission outages are ranked second (30%), which reveals inability to meet ALR.1, ALR.2 and ALR.3 requirements. Generation outages are placed third (10%) because the majority of generation outages have less impact to the grid since operating reserves are allocated to preserve load and generation balance. Duration of the event and unacceptable equipment damage are not included in the example illustrated in Figure 3 due to data unavailability. The final severity and impact scores/percentages will be determined by industry experts and stakeholders as appropriate. The values presented here represent an example for concept development.

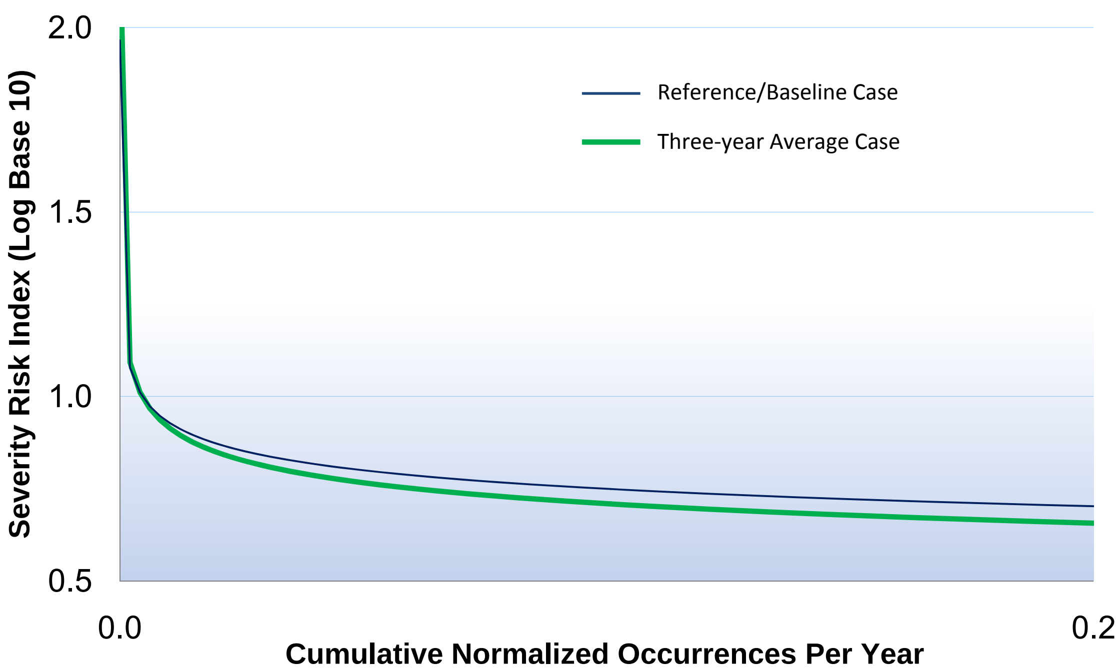
Figure 37 – Example of BPS Risk Assessment for Risk-Significant Events



The vertical logarithmic axis of the curve displays integrated severity values and historic occurrence rate of the risk event is measured on the horizontal axis. This curve is created by taking all recorded risk events and using a proposed risk event severity scale, determining the risk event's severity. Then the risk events are sorted in descending order and what has emerged is a power distribution curve. While the data is sparse, this sparseness appears to be a by-product of reporting history being somewhat short in addition to reporting thresholds the industry has traditionally operated under. As additional low impact/high frequency data is defined and greater reporting history occurs, it is expected that the ambiguity will diminish and the right end of the curve will become better defined.

Figure 38 presents a sample baseline (blue line) and a three-year average (green line) of severity curves for the Eastern Interconnection, illustrating how the severity results can be used to make risk-informed decisions. While the metrics may show trends or variances from year-to-year, no determination has been made as to what indicates an "acceptable" level of performance. Rather, they show the performance from year-to-year and can be a basis for further root-cause analysis.

Figure 38 - Severity Curves: Reference and 2006-2008 Cases
Eastern Interconnection



Based upon the limited data analyzed to this point, there is a linkage between risk event severity and its occurrence, leading to the further development of the curves discussed in Figures 1 and 2. This hypothesis will continually be tested, and if found to inaccurately portray industry experience, assessment parameters will be modified to incorporate new data points and validate an advanced approach.

HIGH IMPACT/LOW FREQUENCY EVENTS

Measuring and monitoring high impact/low frequency (HILF) risk is another important element of the risk assessment process. Ensuring that the processes and metrics exist to provide visibility into the changing nature of these risks will be critical to risk management efforts. Identifying and monitoring reliability indicators, where they exist, will allow the industry to enact a strategic plan to detect early signs of HILF events and take preventative measures as warranted.

HILF events have recently become a renewed focus for risk managers. These risks have the potential to cause catastrophic impacts on the electric power system, but either rarely occur, or, in some cases, have never occurred. Examples of HILF risks include coordinated cyber, physical, and blended attacks, the high-altitude detonation of a nuclear weapon, and major natural disasters like earthquakes, tsunamis, large hurricanes, pandemics, and geomagnetic disturbances caused by solar weather. HILF events truly transcend other risks due to their magnitude of impact and the scope of the impact (in many cases) reaching beyond the limits of the industry sector, and the relatively limited operational experience in addressing them. Deliberate attacks (including acts of war, terrorism, and coordinated criminal activity) pose especially unique scenarios due to their inherent unpredictability and significant national security implications.

The risks associated with the electric sector have a number of characteristics in common:

- HILF risks have the potential to cause widespread or catastrophic impact to the sector—whether through impact to the workforce in the case of a pandemic, or through widespread physical damage to key system components in the case of a high-altitude electromagnetic pulse event.
- HILF risks generally originate through external forces outside the control of the sector. For example, actions can be taken to avoid vegetation contact with a transmission line. However, no amount of preemptive action will reduce the likelihood of a geomagnetic storm or pandemic.
- HILF events can occur very quickly and reach maximum impact with little warning or prior indication of an imminent risk. Effective response and restoration from HILF events require fast initiation and mobilization exercised through thorough planning.
- Little real-world operational experience generally exists with respect to responding to HILF risks, for the simple reason that they do not regularly occur.
- Probability of HILF risks' occurrence and impact is difficult to quantify. Historical occurrence and severity do not provide a strong indicator of potential future frequency or impacts.

The impact of HILF risks may be measured by applying the similar severity index calculation described in this chapter. Other factors can also be considered, including, but not limited to: population affected (number of customers without power), geographic area affected (Region with no electricity in terms of square miles), time taken to restore power, potential for repeat incidents, intangibles (loss of perception of secure image), and various cost quantifiers (cost of repairing damage; cost of re-fortifying systems to ensure no repeat incidents; cost to consumers; cost to industry due to lost productivity, products, or services; cost to government and taxpayers; cost of increased insurance).

PRIORITIZING AND MANAGING RISK

Once a risk is identified and assessed, effort should be turned to its management and mitigation. Risk management builds on the risk assessment process by seeking answers to several questions: What can be done and what options are available? What are the associated tradeoffs in terms of all costs, benefits, and risks? And what are the impacts of current management decisions on future options?

As mitigating options are further considered, it is impossible to fully protect the system from every threat or threat actor. Sound management of these and all risks must focus on determining the appropriate balance of reliability, protection, and restoration. A successful risk management approach will begin by identifying the threat environment and protection goals for the system, balancing expected outcomes against the costs associated with proposed mitigations.

The concept and framework proposed in this chapter not only serves as an important vehicle to communicate the status of bulk power system reliability, but also provides a basic guide for the stakeholders to follow and make informed decisions to identify trends to lower overall system risk, and communicate the effectiveness of reliability programs (see Figure 39).

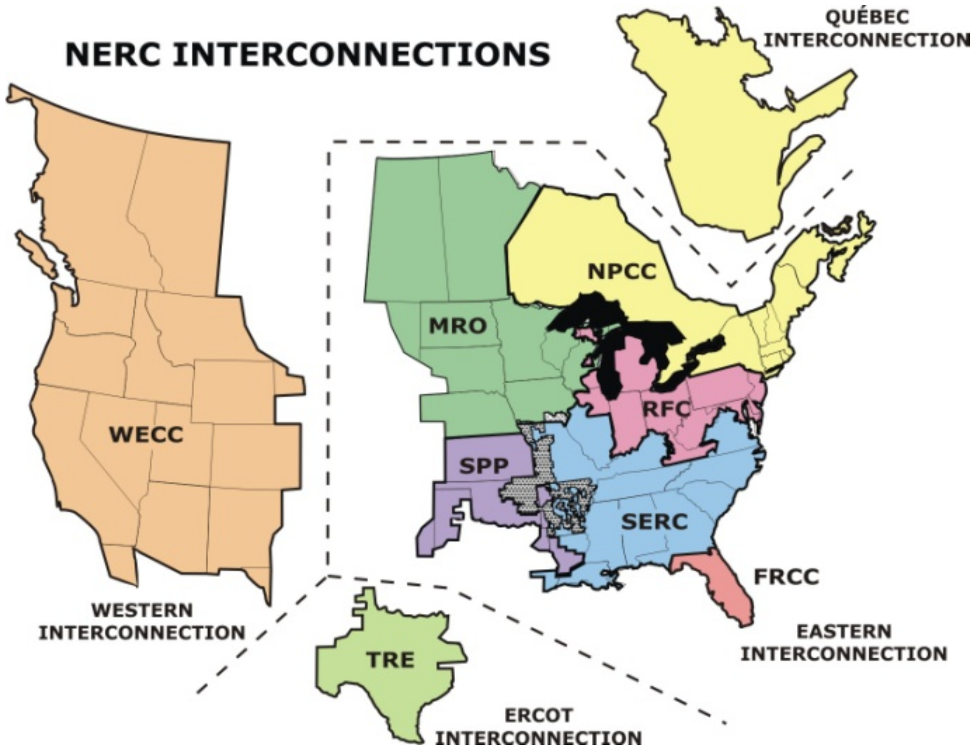
Figure 39: Risk Management Framework for Reliability of the Bulk Power System

Regional Reliability Self-Assessments

Regional Resource and Demand Projections

The figures in the Regional self-assessment pages show the Regional historical demand, projected demand growth, Reserve Margin projections, and generation expansion projections reported by each Region. Highlights are arranged by interconnection and provide information on each Region (see Figure 41).

Figure 41: NERC Regions and Interconnections



EASTERN INTERCONNECTION

FRCC

INTRODUCTION

Florida Reliability Coordinating Council (FRCC) expects to have adequate generating reserves with transmission system deliverability throughout the 10-year planning horizon. In addition, Existing-Other merchant plant capability of 1,438 MW to 1,838 MW is potentially available as future resources of FRCC members and others.

The transmission capability within the FRCC Region is expected to be adequate to supply firm customer demand and planned firm transmission service. Operational issues can develop due to unplanned outages of generating units within the FRCC Region. However, it is anticipated that existing operational procedures, pre-planning, and training will adequately manage and mitigate these potential impacts to the bulk power system.

Table FRCC-1: FRCC Regional Profile (Winter Peak)

	2010	2019
Total Internal Demand	46,245	53,344
Total Capacity	55,856	63,179
Capacity Additions	302	7,624
Demand Response	3,529	4,262

DEMAND

The 2010 ten year demand forecast for the FRCC Region is projected to have a compounded average annual growth rate of 1.3 percent compared to last year's compounded growth rate of 1.8 percent. The decrease in the peak demand forecast growth rate is attributed to an increase in demand side management participation and lower population growth, combined with a continued decrease in economic development as Florida continues to experience the lingering effects of the worst recession in the post World War II period.

FRCC entities use historical weather databases consisting of 20 years or more 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.

Each individual LSE within the FRCC Region develops a forecast that accounts for the actual peak demand. The individual peak demand forecasts are then aggregated by summing these forecasts to develop the FRCC Region non-coincident forecast. These individual peak demand forecasts are coincident for each LSE but there is some diversity at the Region level. The Regional non-coincident forecast is the basis for the evaluation of adequate levels of resources to meet reserve margin requirements. The entities within the FRCC Region plan their systems to meet the Reserve Margin criteria under both summer and winter peak demand conditions.

There are a variety of Energy Efficiency programs implemented by entities throughout the FRCC Region. These programs can include commercial and residential audits (surveys) with incentives for duct testing and repair, high efficiency appliances (air conditioning, water heater, heat pumps, refrigeration, etc.) rebates and high efficiency lighting rebates.

The 2010 ten year Net Internal Demand forecast includes the effects of 3,994 MW of potential demand reductions from the use of load management (3,281 MW) and interruptible demand (713 MW) by 2019. Demand Response is considered as a demand reduction. Entities within the FRCC use different methods to test and verify Direct Load Control programs such as actual load response to periodic testing of these programs and the use of a time and temperature matrix along with the number of customers participating.

Currently there is no Renewable Portfolio Standard (RPS) in Florida. A draft rule was submitted by the Florida Public Service Commission staff to the Florida Legislature for consideration; however, the Florida Legislature has not established Renewable Portfolio Standards in Florida. Projections incorporate demand impacts of new Energy Efficiency programs. Each LSE within the FRCC treats every Demand Side Management load control program as “demand reduction” and not as a capacity resource.

FRCC projected demand is primarily driven by the variability of weather and economic assumptions. Currently, the FRCC is actively evaluating alternative methodologies to evaluate the potential variability in projected demand due to weather, economic, or other key factors. The FRCC is working to develop Regional bandwidths based upon hourly load shape curves for the FRCC Region. 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.

GENERATION

FRCC supply-side resources considered for this ten-year assessment are categorized as Existing (Certain, Other and Inoperable). The FRCC Region counts on 51,338 of Existing-Certain resources of which 44 MW are hydro and 468 MW are Biomass. Potential solar capacity is projected at 33 MW, however, most of this capacity is derated with approximately 3 MW considered as a firm resource available during peak demand, with the remainder being used as an energy-only resource. Existing-Other merchant plant capability of 1,438 MW to 1,838 MW is potentially available as future resources of FRCC members and others.

There is a total of 1,212 MW of Existing-Inoperable resources for 2010. Approximately 1,300 MW of this capacity is being removed for plant modernization, while the balance capacity includes mostly older less efficient generating capacity being placed into operational standby until forecasted loads resume to pre-recessional trends. There is a net total of 456 MW of Future-Planned resources for 2010. By 2019, Future-Planned net resources are expected to be 6,506 MW of which 571 MW are categorized as Biomass, with solar resources achieving almost 13 MW of firm capacity.

FRCC entities have an obligation to serve and this obligation is reflected within each entity's 10-Year Site Plan filed annually with the Florida Public Service Commission. Therefore, FRCC entities consider all future capacity resources as "Planned" and included in Reserve Margin calculations.

Capacity Transactions on Peak

The FRCC Region does not consider Expected or Provisional purchases or sales as capacity resources in the determination of the Region's Reserve Margin. The Firm interregional imports for 2010 are 2,175 MW and are expected to increase by 2019 to 2,372 MW. These imports have firm transmission service to ensure deliverability. The FRCC Region does not rely on external resources for emergency imports and reserve sharing. However, there are emergency power contracts (as available) in place between SERC and FRCC members.

The FRCC Region has 143 MW of generation under Firm contract to be exported during the summer into the Southeastern subregion of SERC throughout 2019. These sales have firm transmission service to ensure deliverability in the SERC Region.

Transmission

Currently, there are 7 miles of 230 kV and 14 miles of 115 kV transmission Under Construction as of 1/1/2010. Presently, there are 356 miles of Planned transmission lines identified throughout the 2010-2019 planning horizon. At this time, it is expected that the target in-service dates of this transmission will be met.

Transmission constraints in the Central Florida area may require remedial actions depending on system conditions creating increased west-to-east flow levels across the Central Florida metropolitan load areas. Permanent solutions such as the addition of new transmission lines and the rebuild of existing 230kV transmission lines are planned and implementation of these solutions is underway. In the interim, remedial operating strategies have been developed to mitigate thermal loadings and will continue to be evaluated to ensure system reliability.

No other significant substation equipment (*i.e.* SVC, FACTS controllers, HVdc, etc.) additions are expected through 2019.

Operational Issues

There are no existing or potential systemic outages of any significance scheduled during seasonal peak periods through the next ten years. Scheduled transmission outages are typically performed during seasonal off-peak periods to minimize any impact to the bulk power system.

The FRCC Region maintains a minimum 15% Reserve Margin to account for higher than expected peak demand due to weather or other uncertainties. In addition, there are operational measures available to reduce the peak demand such as the use of Interruptible/Curtailable load, DSM (HVAC, Water Heater, Pool Pump), Voltage Reduction, customer stand-by generation, emergency contracts and unit emergency capability.

Other than potential impacts due to the April, 2010 Gulf of Mexico (GOM) oil spill, there are no foreseen environmental restrictions identified at this time that could potentially impact reliability in the FRCC

Region throughout the assessment period. There are no direct impacts by the GOM oil spill on FRCC coastal generating capacity at this time[76]. Future and /or longer-term impacts are to be determined, if any.

There is the potential for serious impact to reliability due to regulatory restrictions from aggressive EPA initiatives, with proposed rules on: coal combustion residuals and products under RCRA, waste water discharge regulation under the CWA, cooling water intake structures under CWA section 316(b), CAA MACT rulemakings for mercury and other HAPS, the CAIR and CAMR replacement rules and new AAQSs for PM2.5, SO2, NO2 and Ozone. In addition, regulation of GHG under the CAA as well as a series of other laws can also affect reliability. The combination has the potential for serious impact to reliability as entities struggle to schedule the required overlapping maintenance outages of major fossil generating units and the premature retirement of older units.

No operational changes are needed due to the integration of variable resources through 2019 unless new mandates require the addition of a significant amount of variable resources, in which case these mandates could have the potential for serious impact to reliability.

No operational changes are expected due to the integration of distributed resources through 2019.

Demand Side Management load control programs within the FRCC are treated as "demand reduction" and not as a capacity resource. The expected levels of demand reduction programs throughout the FRCC Region are not expected to cause any reliability concerns.

Reliability Assessment Analysis

The Florida Public Service Commission (FPSC) 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[77] that is produced each year and filed with the Florida Public Service Commission.

The FRCC 2010 Load and Resource Plan shows the average FRCC Reserve Margin of 21 percent over the summer peaks and a 28 percent Reserve Margin over the winter peaks for the next ten years. The 15% (20% for Investor Owned Utilities) Reserve Margin criteria required by the FPSC applies to all 10 years of the planning horizon. The calculation of Reserve Margin includes firm imports into the Region and does not include excess merchant generating capacity (Energy-Only) that is not under a firm contract with a load serving entity. The FRCC Region does not rely on external resources for emergency imports and reserve sharing. However, there are emergency power contracts (as available) in place between SERC and FRCC entities.

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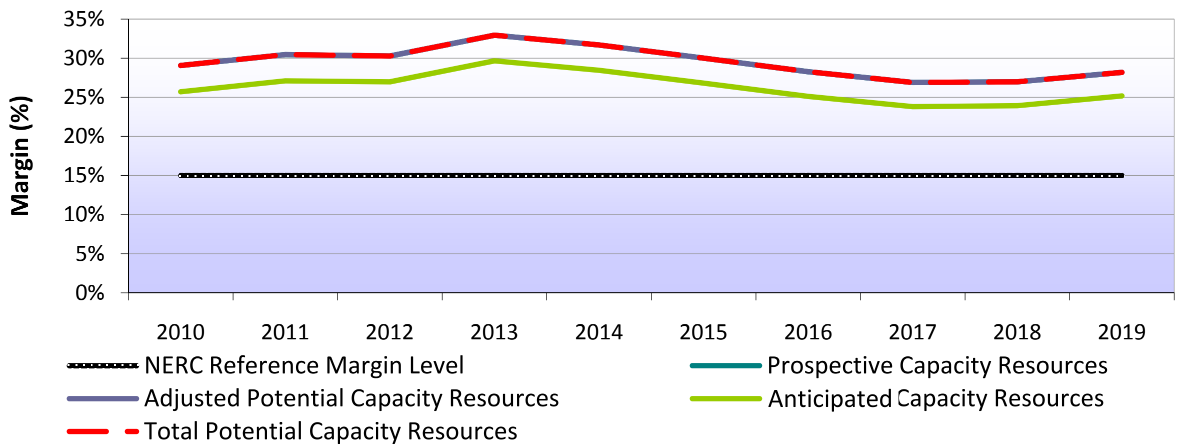
[76] https://www.frcc.com/Documents/FRCC%20Key%20Messages%20-%20Gulf%20Oil%20Spill.pdf

[77] https://www.frcc.com/Planning/Shared%20Documents/FRCC%20Load%20and%20Resource%20Plans/FRCC%202010%20Load%20and%20Resource%20Plan.pdf

The FRCC has historically used the Loss of Load Probability (LOLP) analysis to confirm the adequacy of reserve levels for peninsular Florida. The LOLP analysis incorporates system generating unit information (*e.g.*, Availability Factors and Forced Outage Rates) to determine the probability that existing and planned resource additions will not be sufficient to serve forecasted loads. The objective of this study is to establish resource levels such that the specific resource adequacy criterion of a maximum LOLP of 0.1 day in a given year is not exceeded. The results of the most recent LOLP analysis conducted in 2009 indicated that for the "most likely" and extreme scenarios (*e.g.*, extreme seasonal demands; no availability of firm and non-firm imports into the Region; and the non-availability of load control programs), the peninsular Florida electric system maintains an acceptable LOLP well below the 0.1 day per year criterion.

The amount of resources internal to the Region or subregion that are relied on to meet the minimum 15 percent Reserve Margin throughout the assessment period vary from 51,794 MW to 57,844 MW by 2019 (see Figure FRCC-1). The amount of resources external to the Region/subregion that are relied on to meet the Reserve Margin for the assessment period vary from 2,175 MW up to 2,372 MW by 2019. A 15% (20% for Investor Owned Utilities) Reserve Margin criteria is required by the FPSC for all 10 years of the planning horizon.

Figure FRCC-1: Summer Peak Reserve Margin Projections



For capacity constraints due to inadequate fuel supply, the FRCC State Capacity Emergency Coordinator (SCEC) along with the Reliability Coordinator (RC) have been provided with an enhanced ability to assess Regional fuel supply status by initiating Fuel Data Status reporting by Regional utilities. This process relies on utilities to report their actual and projected fuel availability along with alternate fuel capabilities, to serve their projected system loads. This is typically provided by type of fuel and expressed in terms relative to forecast loads or generic terms of unit output, depending on the event initiating the reporting process. Data is aggregated at the FRCC and is provided, from a Regional perspective, to the RC, SCEC and governing agencies as requested. Fuel Data Status reporting is typically performed when threats to Regional fuel availability have been identified and is quickly integrated into an enhanced Regional Daily Capacity Assessment Process along with various other coordination protocols. These processes help improve the accuracy of the reliability assessments of the Region and ensure optimal coordination to minimize impacts of Regional fuel supply issues and/or disruptions on Bulk Electric System facilities and customers.

Fuel supplies continue to be adequate for the Region as exhibited during an unprecedented 2010 winter peak period which resulted in a new all-time coincident peak for the FRCC Reliability Coordinator Area. Regional operators continue to develop mitigation strategies to minimize the effects of supply impacts due to extreme weather during peak load conditions, including fuel supply and transportation diversity as well as alternate fuel capabilities. There are no identified fuel availability or supply issues at this time. Based on current fuel diversity, alternate fuel capability and on-going fuel reliability analyses, the FRCC does not anticipate any fuel transportation issues affecting capability during peak periods and/or extreme weather conditions.

The calculation of Reserve Margin includes firm imports into the Region and does not include merchant generating capacity (Energy-Only) that is not under a firm contract with a load serving entity. Only firm resources with firm non-recallable contracts are considered in determining resource adequacy for the Region. Energy from variable resources is taken into consideration for energy projections, but the capacity from these variable resources is not included in calculations of Regional Reserve Margins.

There are no planning changes needed throughout the assessment period due to the integration of variable or distributed resources.

Demand Response is considered as a demand reduction. Entities within the FRCC use different methods to test and verify Direct Load Control programs such as actual load response to periodic testing of these programs and the use of a time and temperature matrix along with the number of customers participating.

There are no reliability impacts identified within the FRCC Region due to unit retirements. The majority of the units in the FRCC Region that are classified to be retired are typically converted and re-powered to run on natural gas.

The FRCC Region has approximately 700 MW of load set for Under Voltage Load-Shedding (UVLS) in localized areas to prevent voltage collapse because of a contingency event. The UVLS system is designed with multiple steps and time delays to shed only the necessary load to allow for voltage recovery. At this time no additional load is planned to be set for UVLS throughout the planning horizon time period.

The FRCC does not have any planned additional special protection systems/remedial action schemes throughout the planning horizon time period.

Based on past operating experience with the impact of hurricane to the fuel supply infrastructure within the Region, the FRCC developed a Generating Capacity Shortage Plan.[78] This plan can distinguish

[78] https://www.frcc.com/handbook/Shared%20Documents/EOP%20-%20Emergency%20Preparedness%20and%20Operations/FINAL%20FRCC%20Generating%20Capacity%20Shortage%20Plan.pdf

between generating capacity shortages caused by abnormally high system loads and unavailable generating facilities from those caused by short-term, generating fuel or availability constraints. Since a significant portion of electric generation within Florida uses remotely supplied natural gas, the plan specifically distinguishes generating capacity shortages by primary causes (*e.g.*, hurricanes and abnormally high loads) in order to provide a more effective Regional coordination. The FRCC Operating Committee has also developed the procedure, FRCC Communications Protocols – Reliability Coordinator, Generator Operators and Natural Gas Transportation Service Providers[79], to enhance the existing coordination between the FRCC Reliability Coordinator and the natural gas pipeline operators in response to FERC Order 698. In addition, the FRCC Operating Reliability Subcommittee, through its Fuel Reliability Working Group continues to periodically review and assess the current fuel supply infrastructure in terms of reliability for generating capacity.

The FRCC Region participants perform various transmission planning studies addressing NERC Reliability Standards TPL-001 – TPL-004. These studies include long-range transmission studies and assessments, sensitivity studies addressing specific issues (*e.g.*, extreme summer weather, off-peak conditions), interconnection and integration studies and interregional assessments.

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.

In addition, the transmission expansion plans representing the longer-term study are typically under review by most transmission owners still considering multiple alternatives for each project. Therefore, since specific transmission projects have not been identified or committed to by most transmission owners, these projects are not incorporated into the load flow databank models. The results show local loading trends throughout the FRCC Region as expected given the uncertainties discussed above. No major projects requiring long lead times were identified.

Under firm transactions, reactive power-limited areas can be identified during transmission assessments performed by the FRCC. These reactive power-limited areas are typically localized pockets that do not affect the bulk power system. The *"FRCC Long Range Study 2010-2019"* did not identify any reactive power-limited areas that would affect the bulk power system through 2019. The FRCC Region has not identified the need to develop specific criteria to establish a voltage stability margin.

[79] https://www.frcc.com/handbook/Shared%20Documents/EOP%20-%20Emergency%20Preparedness%20and%20Operations/FRCC%20Communications%20Protocols%20102207.pdf

FRCC transmission owners evaluate new technologies such as FACTS devices and high temperature conductors to address specific transmission conditions or issues. Presently, there are several transmission lines constructed with high temperature conductors within the FRCC Region. However, at this time there are no FACTS devices installed within the Region. FRCC transmission owners consider enhancements to existing transmission planning tools (*e.g.*, enhancements to existing software, new software, etc.) to address the expected planning needs of the future.

Entities within the FRCC Region may consider a wide range of programs to be smart grid programs. For example, some entities have been implementing programs that provide operational flexibility to minimize the number of customers potentially impacted during a distribution outage or manage distribution level feeder voltage control. A large number on Florida entities are in the process of installing two-way communication smart meters. The smart meters will enhance the information available to the customers and allow customers the ability to control usage during peak times. Other entities have added extensive demand-response programs, including smart thermostats and advanced load control systems for commercial customers.

Load serving projects can be delayed, deferred and/or cancelled in response to the latest load forecasts. These load forecasts have been reduced to reflect the anticipated economic conditions throughout the FRCC Region for the upcoming summer. However, there are no expected impacts on reliability through 2019 due to the degraded economic conditions within the Region.

REGION DESCRIPTION

FRCC's membership includes 29 Regional Entity Division members and 25 Member Services Division members, which is composed of investor-owned utilities, cooperative systems, municipal utilities, power marketers, and independent power producers. The FRCC Region is typically summer peaking and divided into 11 Balancing Authorities. As part of the transition to the ERO, FRCC has registered 72 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.[80]

[80] https://www.frcc.com/default.aspx

MRO

Executive Summary

The forecasted 2010–2019 Non-Coincident Peak Net Internal Demand for the MRO Region shows an increase at an average rate of 1.37 percent per year as compared to 1.60 percent predicted last year for the 2009–2018 period. The Total Internal Demand for 2019 is projected to be 54,392 MW. The Net Internal Demand is projected to be 51,113 MW. These projected demands are slightly lower than the 2018 demand projections due to the economic downturn. The Existing capacity resources for 2010 are 65,508 MW. The Existing-Certain resources for 2010 are 58,006 MW. This is 1,573 MW higher than the Existing-Certain resources reported for the 2009 (56,433 MW). The Future (Planned and Conceptual) capacity resources that are projected to be in service by end of 2019 is 19,164 MW. Approximately 1,600 MW of additional nameplate wind generation and 480 MW of hydro generation are projected to be placed in service in 2010 summer since 2009 summer. The projected Adjusted Potential Resources Reserve Margin for the MRO Region ranges from 29.0 percent to 22.7 percent for the 2010-2019 period, which is above the various target reserve margins established by the MRO Planning Authorities.

Table MRO-1: MRO Regional Profile

	2010	2019
Total Internal Demand	48,430	54,392
Total Capacity	65,508	67,629
Capacity Additions	0	2,121
Demand Response	3,199	3,279

A number of transmission reinforcements and various transformer and substation expansions and upgrades are projected to be completed during the 2010-2019 planning horizon. The MRO Transmission Owners estimate that 833 miles of 500 kV DC circuit, 31 miles of 500 kV AC circuit, 894 miles of 345 kV circuit and 570 miles of 230 kV circuit of planned facilities could be installed in the MRO Region over the next ten years.

The MRO Region is projected to have approximately 23,663 MW of nameplate wind generation by end of 2019, which includes Conceptual wind resources based on a 35 percent confidence factor. The simultaneous output of wind generation within the MRO Region has historically reached 75 percent or more of nameplate rating for extended periods of time, and this may occur during off-peak hours and minimum load periods. At the present time, ramp rates, output volatility, and the inverse nature of wind generation with respect to load levels have been manageable. However, the Reliability Coordinator and Operators in the MRO Region closely monitors the ramp-down rate of wind generation during the morning load pickup period. Extensive analysis is being performed on wind generation, in areas such as: regulation, load following, ramp rates, managing minimum load periods, forecasting, equitable participation during curtailments and redispatch. In addition, addressing future aspects of wind such as establishing appropriate capacity credits, day-ahead participation in market processes, and energy storage are being analyzed.

Introduction

The Midwest Reliability Organization (MRO) is a Cross-Border Regional Entity representing the upper Midwest of the United States and Canada. MRO is organized consistent with the Energy Policy Act of 2005 and the bilateral principles between the United States and Canada.

Sufficient generating capacity is forecasted within the MRO Region to maintain adequate reserve margins through 2019. With adjusted potential resources included from the generation interconnection queues in the MRO Region, a proxy Regional target reserve margin level of 15.0 percent for the six MRO Planning Authorities is projected to be met through 2019.

Through the 2019 planning horizon, the assessment shows that the transmission system in the MRO Region is projected to perform adequately assuming planned reinforcements are completed on schedule. The MRO Transmission Owners estimate that 833 miles of 500 kV DC circuit, 31 miles of 500 kV AC circuit, 894 miles of 345 kV circuit and 570 miles of 230 kV circuit of planned facilities could be installed in the MRO Region over the next ten years.

Demand

The compounded annual growth rate of the summer peak Net Internal Demand for the MRO-U.S. subregion is forecasted to be 1.24 percent during the 2010–2019 period as compared to 1.56 percent predicted last year for the 2009–2018 period. The decrease in projected demands is due to the economic downturn. The compounded annual growth rate for the MRO-Canada subregion is forecasted to be 2.08 percent during the 2010–2019 period as compared to 1.75 percent predicted last year for the 2009–2018 period.

While the MRO Region as a whole is summer-peaking, the MRO-Canada is a winter-peaking subregion. The compounded annual growth rate of the winter peak Net Internal Demand for MRO-Canada is forecasted to be 1.89 percent during the 2010–2019 period as compared to 1.68 percent predicted last year for the 2009–2018 period. This increase in load forecast is driven by higher residential load growth due to projected increases in population growth and increases in industrial load due to pipeline expansions, mining and smelting operations.

Peak demand uncertainty and variability due to extreme weather, economic conditions, and other variables are accounted for within the determination of adequate generation reserve margin levels. Most of MRO Planning Authorities use a Load Forecast Uncertainty (LFU) factor that considers uncertainties attributable to weather and economic conditions. Saskatchewan develops energy and peak demand forecasts based on a provincial econometric model and forecasted industrial load data. Forecasts take into consideration the Saskatchewan economic forecast, historic energy sales, customer forecasts, normalized weather and historical data, and system losses.[81]

[81] Saskatchewan 2009 Load Forecast Report.

Each individual Load Serving Entities (LSE's) member within the MRO Region maintains reserves based on its monthly peak load forecasts. The LSE's reported based solely on its own peak, which could occur at a different time than the system peak. The individual LSE's monthly peak load forecasts are then aggregated by summing these forecasts to develop the MRO Regional non-coincident demand forecast. The Regional non-coincident demand forecast does not include any diversity factors.

Interruptible Demand and Demand-Side Management (DSM) programs, presently amounting to 3,199 MW, are used by a number of MRO members. The Interruptible Demand and Demand-Side Management (DSM) programs are projected to increase to 3,279 MW by 2019. A wide variety of Energy Efficiency programs, including conservation, consumer education, direct load control (such as electric appliance cycling) and interruptible load are used to reduce peak demand. Reductions in demand due to Energy Efficiency are not known at this time.

Each MRO member uses its own forecasting method, meaning some may use a 50/50 forecast, some may use a 90/10 forecast or forecasts based on a provincial econometric model. In general, the peak demand forecast includes factors involving recent economic trends (industrial, commercial, agricultural, residential) and normal weather patterns.

GENERATION

The Existing (Certain, Other & Inoperable) capacity resources for 2010 summer are 65,508 MW. The Future (Planned and Other) capacity resources that are projected to be in service by end of 2019 are 3,992 MW. These values do not include import and export capacity transactions.

The nameplate capacity of the Existing variable generation for the MRO Region is approximately 7,540 MW for 2010 summer. The variable resources for the MRO-US subregion projected to be available at peak times are 570 MW, based on 8 percent of nameplate capacity for summer peak. The nameplate capacity of the Future variable generation for the MRO Region is estimated to increase to 1,770 MW by 2019. The variable resources for the MRO-US subregion projected to be available at peak times are estimated to increase to 131 MW by 2019 based on 8 percent of nameplate capacity for summer peak. The 8 percent for summer peak and 20 percent for winter peak of nameplate wind generation is used for the MRO-US subregion only. The 8 percent and 20 percent of nameplate capacity rule is used by MRO-US Planning Authorities when determining capacity credits of variable generation. 10 percent of nameplate wind generation is used for the MRO-Canada subregion for summer peak and 20 percent for winter peak. The existing biomass portion of resources for the MRO Region projected to be available at peak times is 156 MW. Future-Planned biomass is estimated to increase to 43 MW over the next ten-years.

The Conceptual capacity resources projected to come on-line for the MRO Region are estimated to increase to 15,172 MW by 2019 based on a 35 percent confidence factor. The Conceptual nameplate capacity of variable generation projected for the MRO Region is estimated to increase to 14,353 MW by 2019. The Conceptual variable resources for the MRO-US subregion projected to be available at peak times are 1,148 MW, based on 8 percent of nameplate capacity for summer peak. The 8 percent for summer peak and 20 percent for winter peak of nameplate wind generation is used for the MRO-US subregion only. The 8 percent and 20 percent of nameplate capacity rule is used by MRO Planning

Authorities when determining capacity credits of variable generation. 10 percent of nameplate wind generation is used for the MRO-Canada subregion for summer peak and 20 percent for winter peak. The Conceptual biomass portion of resources for the MRO Region is estimated to increase to 77 MW over the next ten-years.

Conceptual capacity resources were acquired from various generation interconnection queues within the Region that are active, or have initiated study work or agreements with the Transmission Provider. The majority of the Conceptual capacity resources in the MRO Region are wind generation. Much of this wind generation is being proposed within the next three years since federal Production Tax Credits for wind generation are presently effect through 2012.

A confidence factor was applied across each of the study years starting with 10 percent for 2011 through 35 percent for the 10th year to reduce the Conceptual capacity resources amount to a realistic projected value. This value is judged to be conservative and should not result in overstated Conceptual capacity resources.

There are uncertainties involved when using Conceptual capacity resources from applicable generation interconnection queues. In-service dates may be deferred or slip and some generation that is projected within the next several years may in fact qualify as “Planned” resources. Conceptual capacity resources from generation interconnection queue were coordinated with generation owners to verify and update in-service dates of key future generation (*i.e.*, large coal units) and to establish a reasonable confidence factor. MRO also considered when establishing the confidence factor that the LSE’s within the MRO Region have an obligation to serve and meet their target reserve margins.

CAPACITY TRANSACTIONS ON PEAK

For the 2010, the projected total firm imports into the MRO Region are 1,993 MW. These imports are from sources external to the MRO Region. A total firm export of approximately 1,675 MW is projected for 2010 to serve loads outside of the MRO Region. The net import or export of the MRO Region may vary at peak load, depending on system conditions and market conditions. The total firm exports become progressively lower in future years while imports varied minimally through the study period.

Transfer capability from MRO-Canada (Saskatchewan and Manitoba) subregion into the MRO-US subregion is limited to 2,415 MW due to the operating security limits of the two interfaces between these two provinces and the U.S. The forecasted firm and expected on-peak transfers from MRO-Canada to the U.S. is 1,160 MW for 2010 and is estimated to decrease to 725 MW over the next ten-years.

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

Transmission

A number of transmission reinforcements and various transformer and substation expansions and upgrades are projected to be completed by 2010-2019 planning horizon. These planned reinforcements include several rebuilt or reconductored transmission lines.

The majority of the planned transmission for the MRO-Canada subregion is for hydro resource integration reinforcements.

There are no reliability concerns in meeting target in-service dates of the transmission projects. Operational procedures to maintain reliability will be implemented if unforeseen delays occur in these or other planned projects.

The Iowa system continues to see a large amount of new wind farm installations. The main driver in electric system improvements has been the large increase of installed wind generation. The Iowa system continues to experience the effects of several other forces including a surge of installed wind power in Minnesota and central Illinois. The eastern Iowa system has several flowgates impacted by high south to north flows that may occur for any load condition. The planned Salem to Hazleton 345 kV line will help alleviate these constraints.

The Nebraska transmission system is heavily impacted by north-to-south and west-to-east Regional transfers. System operating limits have been approached on north-to-south flowgates including the Western Nebraska – Western Kansas (WNE_WKS) and Cooper South (COOPER_S) Interfaces during these high transfers which predominately occur during off-peak time periods. For those time periods in which heavy flows to the south do occur, operating guides are in place to implement transmission loading relief and market redispatch to limit flows. Future transmission plans such as the Axtell – Post Rock - Spearville 345 kV line addition will help to alleviate these constraints as well as other transmission constraints.

The Wisconsin-Upper Michigan Systems (WUMS) southern interface includes tie lines in the southwest and southeast interfaces. The southwest interface comprises the Wempletown-Paddock 345 kV line and Wempletown-Rockdale 345 kV line. The southeast interface comprises Zion-Arcadian 345 kV line, Zion-Pleasant Prairie 345 kV line and Zion-Lakeview 138 kV line. The WUMS southern interface is thermally limited during periods of heavy transfer in either direction. The WUMS southern interface is also voltage stability limited during periods of heavy imports through the interface. Operating guides including coordinated reciprocal flowgates of the Midwest ISO and PJM RTO are used to monitor and manage these constraints. Completion of the second Paddock - Rockdale 345 kV line in March 2010 will help alleviate the southwestern interface constraints. The southeastern interface constraints are further being addressed by ATCLLC's analysis of transmission projects that potentially provide economic benefits, particularly, a Bain – Zion 345 kV line, and Midwest ISO's Cross Border Top Congested Flowgates Study.

The Minnesota-Wisconsin Export (MWEX) interface is comprised of the Arrowhead 230 kV phase shifting transformer and King-Eau Claire 345kV line. During high imports from Minnesota into WUMS across the MWEX interface, the system would be more susceptible to transient voltage instability issues than thermal issues during light load conditions. An operating guide including coordinated reciprocal flowgates of the Midwest ISO and MAPP are in placed to monitor and manage these constraints to acceptable limits to ensure reliable operation of the transmission system. The proposed Twin Cities-North La Crosse 345 kV line (Hampton Corner – North Rochester – North La Crosse) and the ATCLLC La Crosse-Cardinal 345 kV line will address the export concerns across this interface resulting in redefinition of the interface or potential elimination of the interface. Further analysis will be performed as the proposed facilities advance forward.

The North Dakota Export (NDEX) interface is comprised of multiple tie lines that connect various parts of the transmission system together between Minnesota and the Dakotas. During high exports from the Dakotas into Minnesota, the NDEX interface sees increased loading during light load conditions, which may result in the transmission system being susceptible to transient voltage instability. Operating guides are in place to manage NDEX interface flow to acceptable limits to ensure reliable operation of the transmission system. The proposed Fargo-Monticello 345 kV and Bemidji-Grand Rapids 230 kV lines will both cross the existing NDEX interface and are projected to create additional interface capability between the Dakotas and Minnesota. Transmission studies underway for the planning horizon are evaluating the historical NDEX interface and considering a potential redefinition of the interface to include the proposed projects. Further analysis will be performed as the proposed facilities advance forward.

The eastern portion of the Upper Peninsula of Michigan (UP) experiences flows in both west to east and east to west directions. Heavy flows in either direction may cause Midwest ISO to initiate market redispatch or ATCLLC to open the 69 kV lines between the eastern UP and the rest of the WUMS system, using procedures defined in an operating guide. The transmission plans under development at ATCLLC through the UP Collaborative initiative will help alleviate these constraints. This includes the installation of AC-DC-AC power flow controller or phase shifting transformers at the Straits 138 kV substation.

Other significant substation equipment anticipated to be in service in MRO Region in the 2010 through 2019 planning horizon are as follows:

- Install AC-DC-AC power flow controller or phase shifting transformers at the Straits 138 kV substation
- Thompson Birchtree 95/-50 MVAr SVC
- Riel synchronous condensers (4 X 250 MVAr)
- 100 MVAr SVS in south-central Saskatchewan

Operational Issues

There are no known operational issues for the next ten years other than existing system constraints identified above. Operating studies have been or will be performed for all scheduled transmission or generation outages. When necessary, temporary operating guides will be developed for managing the scheduled outages to ensure transmission reliability. Resource adequacy would be offset by planning reserves and external markets. If necessary, operational measures included in emergency operation plans include interruptible load, public appeals, and rotating outages.

The potential of CO_2 regulations as well as the requirement to reduce Critical Air Contaminants such as SO_2 and NO_x for MRO-US subregion could cause restrictions to high emitting technologies. The magnitude is unknown at this time. Environmental and regulatory requirements restrict the operation of the Manitoba Hydro Brandon #5 generating unit (100 MW) except during certain emergency conditions. This, however, will not impact the reliability of the interconnected system.

The MRO Region is projected to have approximately 23,663 MW of nameplate wind generation by end of 2019. There is a potential ambient temperature restriction (*e.g.*, some wind turbines may be restricted to operating in ambient temperatures between -20 degrees F and 104 degrees F) with wind turbines. However, accurate forecasting will help to identify any near-term concerns regarding ambient temperature limits.

Wind generation in Iowa will continue to cause implementation of congestion management procedures during high wind conditions. Some prior outage conditions will require establishing limits on wind farm outputs or fast reduction of wind generation. Operating guides are in place to address post-contingent and real-time loading on underlying 69 kV facilities. Midwest ISO Market LMP/binding procedures are used for congestion management when needed. Overall, the Iowa system is projected to operate in a reliable manner.

Sudden increases or decreases of levels of wind generation in Iowa and Minnesota have demonstrated significant impact on driving the flows through the WUMS western and southern interfaces, MWEX and SOUTH TIE interface, respectively. ATCLLC and the Midwest ISO are monitoring this operational issue closely. A real-time hourly operational study is performed by the Midwest ISO to anticipate the impacts of the sudden change in wind generation in Iowa and Minnesota on a number of selected Flowgates. Operators are alerted when the loading of any monitored Flowgate comes within 95 percent of its rating.

There are no known operational concerns resulting from generation connected to the distribution system. The MRO Region does not expect any reliability concerns resulting from high-levels of Demand Response resources.

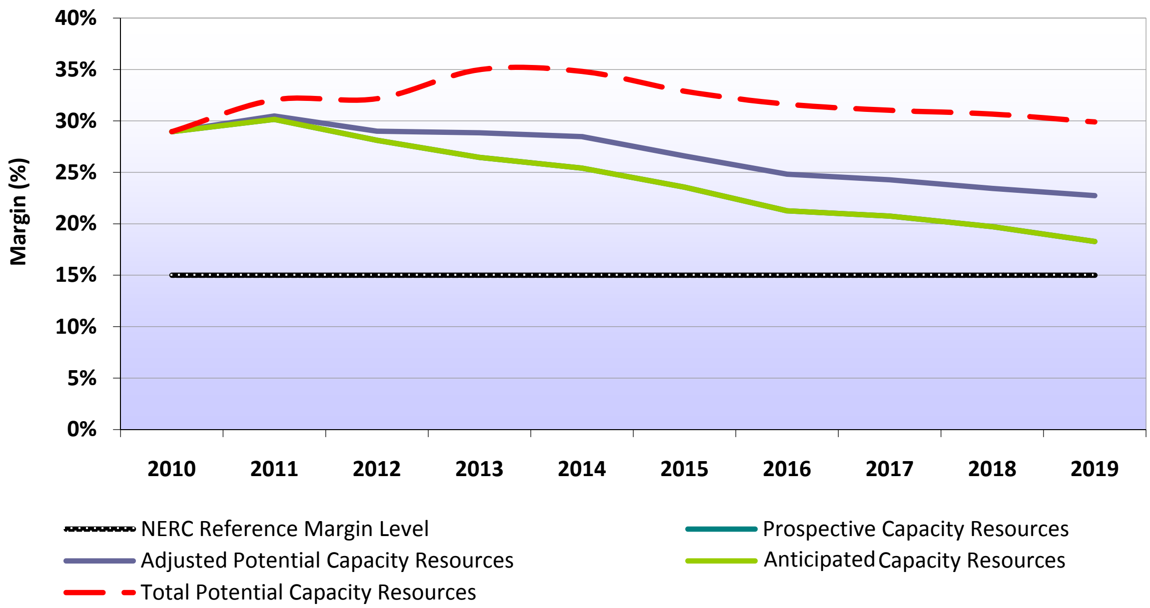
Reliability Assessment Analysis

The MRO's Regional projected Adjusted Potential Resources Reserve Margin ranges from 29.0 percent to 22.7 percent for the 2010-2019 period (see Figure MRO-1). Based on summer peak, the Reserve Margins for all the ten-years exceed the proxy Regional target Reserve Margins of 15 percent. Each MRO Planning Authority has a distinct Reserve Margin target. Basin Electric Power Cooperative and Western Area Power Administration use a planning reserve margin identified in the Loss of Load Expectation (LOLE) study performed and completed by MAPP on December 30, 2009. The MAPP Region applies a minimum of 15 percent reserve margin for predominantly thermal systems, and a minimum of 10 percent reserve margin for predominantly hydro systems.[82] The Midwest ISO has conducted a Loss of Load study establishing a minimum of 11.94 percent reserve margin requirement based on non-

[82] MAPP Loss-of-Load Expectation (LOLE) Study for the ten-year Planning Horizon 2010-2019, http://www.mapp.org/ReturnBinary.aspx?Params=584e5b5f405c567900000002cb.

coincident load for all Midwest ISO load-serving entities.[83] Both the Mid-Continent Area Power Pool (MAPP) and the Midwest ISO members within the MRO Region use a Load Forecast Uncertainty (LFU) factor within the calculation for the LOLE and the percentage reserve margin necessary to obtain a LOLE of 0.1 day per year or 1 day in 10 years. A minimum planning reserve margin of 13.6 percent applies to Nebraska's Balancing Areas as indentified in the LOLE study performed and completed by SPP on June 2009.[84] The study estimates the reserve margin required to obtain a LOLE of 0.1 day per year or 1 day in 10 years. Saskatchewan's reliability criterion is based on annual Expected Unserved Energy (EUE) analysis and equates to a minimum of 13 percent reserve margin.[85] The projected MRO's Regional reserve margin of 29.0 percent to 22.7 percent is in excess of these target reserve margins.

Figure MRO-1: Summer Peak Reserve Margin Projections



To meet the target margin levels, the MRO subregions rely on their internal resources only. No specific assessment is performed to ensure external resources are available and deliverable. However, to be counted as firm capacity, the various transmission providers require external purchases to have a firm contract and firm transmission service.

Reservoir water levels in the MRO-U.S subregion are adequate to meet reserve margin needs. However, from an energy perspective, reservoir water levels throughout the northern MRO-U.S. subregion (Montana, North Dakota, and South Dakota) have improved in recent years, but continue to remain below normal. For MRO-Canada subregion, generation on the Manitoba hydro units is projected to be about 82 percent of normal for 2010 summer. Hydro unit limitations due to requirements for

[83] Midwest ISO 2010 LOLE Report http://www.midwestmarket.org/publish/Document/13b9ea_1265d1d192a_-7b910a48324a.

[84] 2008 SPP LOLE Study – 2009 Update

[85] Saskatchewan 2009 Supply Development Plan.

endangered species will continue until such requirements are lifted. The Manitoba Hydro generation is planned to be adequate to supply Manitoba load and contracted firm export based on the lowest hydraulic flows on record (worst drought experienced in Manitoba). Saskatchewan does not anticipate any fuel delivery problems. Fuel-supply interruption in Saskatchewan is generally not considered an issue due to system design and operating practices. Saskatchewan reservoirs are expected to be at below normal conditions but near-normal operating regimes are expected. Reservoir levels are sufficient to meet peak demand. Low reservoir levels are expected to result in reduced energy output, but will not affect system reliability.

Resource unavailability within the MRO Region would be offset by planning reserves and external markets. If necessary, operational measures, which would include emergency plans, interruptible load, public appeals, and rotating outages, would be implemented. The MRO Region does not depend on energy-only or transmission-limited resources to achieve its resource adequacy target.

Renewable Portfolio Standards from the U.S. Department of Energy website, which does not include Canadian provinces, are shown in the table below.

Table MRO- 2: Renewable Portfolio Standards per US Department of Energy

State/Province	Amount (in percent Energy or MW)	Year
Minnesota	25 percent	2025
Iowa	105 MW	---
Montana	15 percent	2015
Wisconsin	10 percent	2015
South and North Dakota (Objective)	10 percent	2015
Nebraska	None	--
Manitoba	None	--
Saskatchewan	None	--

For resource adequacy assessment, 8 percent for summer peak and 20 percent for winter peak of nameplate wind generation are considered for the MRO-US subregion. 10 percent for summer peak and 20 percent for winter peak of nameplate wind generation are considered for the MRO-Canada subregion. Planning for wind resources involves appropriate siting for transmission infrastructure and wind regimes. Future wind installations will also be curtailed to meet operating needs.

Demand-side management, such as interruptible load and direct–control load management, was accounted for in the emergency operation procedures. Demand Response is currently not used for resource adequacy assessment. MRO members are reviewing the development of Demand Response programs.

The reliability impact due to retirement of generating units in the MRO Region is evaluated by MRO Planning Authorities and affected entities. Under the Midwest ISO procedure, if the potential retirement of a unit causes reliability concerns that could not be addressed by feasible alternatives, such as generation re-dispatch, system re-configuration, transmission reinforcement acceleration, etc, then the unit will be required to operate under a System Supply Resource (SSR) agreement with the Midwest ISO until such alternatives become available.[86] The reliability impact due to retirement of generating units in the MAPP Planning Authority footprint is evaluated by the MAPP Design Review Subcommittee in coordination with generation and transmission owners. Saskatchewan has planned unit retirements over the next ten-years that have been included in the reliability assessment. Unit retirements are offset by unit additions in Saskatchewan's Supply Plan.

ATCLLC is planning to install a Special Protection System (SPS) as part of the Monroe County-Council Creek 161 kV line project in 2013 in lieu of rebuilding the 23 mile 138 kV line between Petenwell and Saratoga substations. This SPS will be retired if this 138 kV line is rebuilt in the future.

Emergency conditions within the MRO Region would be managed through the Reliability Coordinators and Operators. Resource or, transmission deficiencies are offset by planning reserves and external markets. If necessary, operational measures, which include emergency plans, interruptible load, public appeals, and rotating outages, would be implemented.

Planning studies are performed annually by the MRO Planning Authorities. MAPP performs a reliability assessment annually. The MAPP System Performance Assessment is an assessment to develop an understanding of the transmission system topology, behavior and operations.[87] In addition, the study is done to determine if existing and planned facility improvements identified in Appendix A of the MAPP Regional Plan meets the MAPP Members Reliability Criteria, NERC Transmission Planning Standards TPL-001 thru TPL-004 and, or, applicable MRO Regional standards. This is an assessment of the reliability of the MAPP Region for the present, near term (years one through five) and long-term (years six thru ten) transmission expansion planning.

The Midwest ISO performs annual Transmission Expansion Planning (MTEP) that focuses on reliability and efficient electricity expansion for the next ten years and complies with all relevant NERC Transmission Planning Standards.[88] Efforts are focused on identifying issues and opportunities related to the strengthening of the transmission grid, developing alternatives to be considered, and evaluating those options to determine if there is an effective solution among them. The objective is to identify projects that:

- Ensure reliability of the transmission system
- Provide economic benefit, such as through allowing increased efficiency in market operations (*i.e.* reducing cost of energy production and, or, the price paid by load)
- Enable public policy objectives, such as the integration of renewables, to be achieved
- Address other issues or goals identified through the stakeholder input process.

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[86] http://oasis.midwestiso.org/OASIS/MISO

[87] 2009 MAPP System Performance Assessment

[88] Midwest ISO Transmission Expansion Plan, http://www.midwestiso.org/page/Expansion+Planning.

Nebraska's Balancing Areas participate in the annual SPP Transmission Expansion Plan (STEP) with Regional group of projects to address Regional reliability needs for the next ten-years. [89]

ATCLLC performs annual ten-year planning studies to ensure reliability in planning horizon.[90] ATCLLC also participates in the Midwest ISO Transmission Expansion Plan (MTEP) planning studies to coordinate Regional reliability issues.

Manitoba Hydro performs ongoing system planning studies ranging over the ten year planning horizon to assess and enhance reliability, integrate new generation, address forecast load growth connect new large industrial load and to facilitate transmission service requests. Manitoba Hydro publishes a ten-year Plan annually, which is posted on its website.[91] Manitoba Hydro also conducts a joint long-term reliability assessment with MAPP.

Saskatchewan performs ongoing transmission planning studies to integrate new generation and load and assess reliability, and there are ongoing infrastructure improvements being developed to address any issues identified.[92] Saskatchewan and Manitoba Hydro also perform joint operational planning studies for the MRO-Canada subregion to define transfer capability.[93] The studies define secure transfer capabilities and operational requirements for the season. Studies consider simultaneous transfers to and from Manitoba and North Dakota; and any known transmission and generation issues.

The Midwest ISO launched a three-year program to install more than 150 high-tech monitoring devices that will monitor the state of the electrical grid 30 times each second, increasing the efficiency and reliability of power delivery.[94] The SMART grid programs are part of Midwest ISO's agreement with the U.S. Department of Energy to implement synchrophasors, also known as phasor measurement units (PMUs), to more accurately measure voltage and current within the Eastern Interconnection. PMU measurements could increase available transmission and improve system-wide reliability and stability.

ATCLLC has several SMART Grid programs in process. The first is a relay betterment program which replaces electromechanical relaying with microprocessor based relays. This program is intended to increase system reliability and security via expanded use of carrier and fiber optic communication, decrease outage duration by providing fault location information, provide self monitoring alarm functions, and improve relay coordination. The other two SMART grid programs are part of ATCLLC's DOE funded project. ATCLLC is installing fiber optics in shield wires (OPGW) for improved relay, SCADA, and voice communications. These fiber optic paths provide communications capabilities to ATCLLC that will help us expand into other Smart Grid initiatives as they become available. Additionally, ATCLLC is installing phasor measurement units (PMUs) to measure the power angle across the network.

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[89] http://www.spp.org/publications/2009%20SPP%20Transmission%20Expansion%20Plan%20(Redacted%20Version).pdf

[90] 2009 – ATCLLC ten-Year Transmission System Assessment Update, http://www.atc10yearplan.com;

[91] http://oasis.midwestiso.org/OASIS/MHEB

[92] Saskatchewan 2009 and 2010 Planning Studies

[93] Manitoba Hydro - Saskatchewan Power Seasonal Operating Guideline on Manitoba-Saskatchewan Transfer Capability

[94] http://www.midwestiso.org/page/Recent+News+Details?newsID=253

Other Region-Specific Issues

Because wind generation is a variable 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.

Region Description

The MRO has 116 registered entities. There are seven Balancing Authorities: Lincoln Electric System (LES), Manitoba Hydro (MH), Nebraska Public Power District (NPPD), Omaha Public Power District (OPPD), Saskatchewan Power Corporation (SPC), Western Area Power Administrator (WAPA) and Midwest ISO, which assumes all tariff members under Midwest ISO operate as one Balancing Authority. The MRO Region as a whole is a summer peaking Region; however, both Canadian provinces are winter peaking. The MRO Region covers all or portions of Iowa, Illinois, Minnesota, Nebraska, North and South Dakota, Michigan, Montana, Wisconsin, and the provinces of Manitoba and Saskatchewan. The total geographic area is approximately 1,000,000 square miles with an approximate population of 20 million.

The MRO has six Planning Authorities registered within the footprint: the Midwest ISO, MAPP, American Transmission Company, Southwest Power Pool, Manitoba Hydro, and Saskatchewan Power Corporation. The Midwest ISO also spans into the RFC and SERC Regions. There are three Reliability Coordinators within the MRO footprint, the Midwest ISO, Southwest Power Pool, and Saskatchewan Power Corporation. The majority of Registered Entities within MRO are Midwest ISO tariff members and therefore participate in the Midwest ISO market operations. The Nebraska Balancing Areas are under the Southwest Power Pool tariff and Reliability Coordinator.

RFC

Executive Summary

Both RTOs (PJM and Midwest ISO) within Reliability*First* are projected to have sufficient reserve margins for this assessment period. Therefore, the Reliability*First* Region is expected to have adequate reserves for this assessment period.

The transmission system within the Reliability*First* footprint is expected to perform well over a wide range of operating conditions, provided new facilities go into service as scheduled, and that transmission operators take appropriate action, as needed, to control power flows, reactive reserves and voltages.

However, it is always possible that a combination of high loads due to adverse weather, coupled with high generating unit outages and the unavailability of additional power purchases from the interconnection, could result in the curtailment of firm demand.

Table RFC-1: RFC Regional Profile

	2010	2019
Total Internal Demand	177,688	200,600
Total Capacity	227,083	243,618
Capacity Additions	0	16,535
Demand Response	6,200	9,300

The aggregate connected Total Internal Demand (TID) in the ReliabilityFirst Region for the summer peak is projected to increase by about 22,900 MW from 177,700 MW in 2010, to 200,600 MW in 2019. The compound annualized growth rate (CAGR) in TID for the period 2010 to 2019 is 1.4 percent per year.

The reported generating unit capacity for the summer of 2010 is 217,700 MW. Future, Planned capacity changes project a net increase of 16,600 MW through 2019. Approximately 5,300 MW, 31 percent of the Conceptual capacity resources (16,900 MW) are also expected through 2019. This is a total expected increase of 21,900 MW to 239,600 MW.

When projected capacity additions are included with existing resources, the total generation is sufficient to maintain a 15.0 percent reference reserve margin through 2019.

Plans within Reliability*First* for this assessment period include the addition of over 1,830 miles of high voltage transmission lines that will operate at 100 kV and above, as well as numerous new substations and transformers that are expected to enhance and strengthen the bulk power system. Most of the new additions are connections to new generators or substations serving load centers.

No other unusual operating conditions that could affect reliability are foreseen for this assessment period.

INTRODUCTION

All Reliability*First* Corporation (RFC) members are affiliated with either the Midwest ISO (MISO) or the PJM Interconnection (PJM) Regional Transmission Organization (RTO) for market operations and reliability coordination. Ohio Valley Electric Corporation (OVEC), a generation and transmission company located in Indiana, Kentucky and Ohio, is not a member of either RTO and is not affiliated with their markets; however, PJM performs OVEC's Reliability Coordinator services. Also, Reliability*First* does not have officially designated subregions. The Midwest ISO and PJM each operate as a single Balancing Authority area. Since all Reliability*First* demand is in either Midwest ISO or PJM except for a small load (less than 100 MW) within the OVEC Balancing Authority area, the reliability of the PJM RTO and Midwest ISO are assessed and the results used to indicate the reliability of the Reliability*First* Region.

Midwest ISO members FirstEnergy and Duke Energy have announced their intentions to leave the Midwest ISO and join the PJM RTO. For this assessment, these changes have not been made to the PJM or Midwest ISO demand or capacity data. Since all of the demand and capacity will remain in the Reliability*First* Region, there will be no impact to the Reliability*First* Regional data.

This assessment provides information on projected resource adequacy across the Reliability*First* Region and relies on the reserve margin requirements determined for the PJM and Midwest ISO areas. Analyses were conducted by the Midwest LOLE Working Group and PJM to satisfy the Reliability*First* requirement for Planning Coordinators to determine the reserve margin at which the Loss of Load Expectation (LOLE) is one day in ten years (0.1 day/year) on an annual basis for their planning area. These analyses include demand forecast uncertainty, outage schedules, determination of transmission transfer capability, internal deliverability, other external emergency sources, treatment of operating reserves and other relevant factors when determining the probability of firm demand exceeding the available generating capacity. The assessment of PJM resource adequacy was based on reserve requirements determined from the PJM analysis. Similarly, the assessment of Midwest ISO resource adequacy was based on reserve requirements determined from the Midwest ISO analysis.

Reliability*First's* Resource Assessment Subcommittee believes that it is reasonable to assess the overall resource adequacy of the Reliability*First* Regional area by assessing the resource adequacy of the RTOs that operate within the Regional area. This is possible since the determination of each of the RTO reserve margin targets has been performed in a manner consistent with the requirements contained in Regional reliability standard BAL-502-RFC-002. The Resource Assessment Subcommittee believes that when Reliability*First* has determined that each RTO is projected to have sufficient resources to satisfy their respective reserve margin requirement, therefore the Reliability*First* area is projected to have adequate resources.

DEMAND

The Region is expected to be summer peaking throughout the study period, therefore this assessment will focus its analysis on the summer demand period. In this assessment, the data related to the Reliability*First* areas of PJM (RFC-PJM) and Midwest ISO (RFC-MISO) are combined with the data from OVEC to develop the Reliability*First* Regional data. The demand forecasts used in this assessment are all based on the coincident peak demand of Midwest ISO's local balancing authorities and the coincident peak of PJM's load zones. Both PJM and Midwest ISO demand forecasts are based on an expected or 50/50 demand forecast. These forecasts reflect economic factors from late 2009 economic forecasts and median weather data. Actual demand data from the past three years indicates minimal diversity (less than 100 MW) between the RTO coincident peak demands and the Reliability*First* coincident peak demands. For this assessment, no additional diversity is included for the Reliability*First* Region; therefore, the Reliability*First* coincident peak demand is simply the sum of the PJM, Midwest ISO and OVEC peak demands (rounded to nearest 100 MW). The composite Reliability*First* Region forecast is considered a 50/50 demand forecast.

Midwest ISO has not specifically identified any reductions to their demand forecast explicitly due to Energy Efficiency (EE) programs, although the effects of these programs may be included in its members' forecast data. PJM has a forecast demand reduction of 550 MW due to Energy Efficiency (EE) programs which begins with the 2012 summer demand forecast. The categories of Direct Control Load Management and Interruptible are expected to provide a combined potential Demand Response reduction of 6,200 MW within the Reliability*First* Region increasing to 9,300 MW through the assessment period. The Direct Control Load Management during the 2010 summer is projected to be 900 MW, and the Interruptible Demand is projected to be 5,300 MW. The total demand reduction is the maximum controlled demand mitigation that is expected to be available during peak demand conditions.

PJM has reported that an additional 5,100 MW of load was bid into PJM's 2010 market as a capacity resource. In this assessment, the additional Demand Response reduction is not included.

Since demand reduction programs are a contractual management of system demand, their implementation reduces the reserve margin requirement for the RTO. Net internal demand is TID less the demand reduction. Reserve margin requirements are based on Net Internal Demand.

The estimated coincident Net Internal Demand (NID) peak of the entire Reliability*First* Region for the summer of 2010 is projected to be 171,500 MW. For the summer of 2019, NID is projected to be 191,300 MW. The compound annualized growth rate (CAGR) of the NID forecast is 1.2 percent from 2010 to 2019. This is lower than the 1.4 percent CAGR of last year's NID forecast due to the current forecast of expected economic conditions.

The TID for the summer of 2010 is projected to be 177,700 MW. For the summer of 2019, TID is projected to be 200,600 MW. The CAGR of the TID forecast is 1.4 percent from 2010 to 2019. This is the same as the 1.4 percent CAGR of last year's TID forecast.

Generation

The amount of Existing-Certain capacity in Reliability*First* is 217,700 MW. There is also 9,400 MW of Other Existing capacity in the ten year assessment period, which is not included in the reserve margins analysis.

PJM and MISO analyze historical data from their respective generator interconnection queues. This analysis and the status of each project's interconnection service agreement determines whether a project is categorized as Future, Planned or Conceptual, and the confidence factor to apply to Conceptual projects.

The nameplate rating increase in Future Capacity Additions through 2019 is 30,300 MW, with 16,500 MW being Future-Planned Capacity that is included in the reserve margins. Future-Planned capacity is included in the reserve margin.

The nameplate ratings of the Conceptual projects in the generator interconnection queues are 32,900 MW. The expected on-peak ratings of these projects total 16,900 MW. The amount of Conceptual capacity in the reserve calculation (5,300 MW) is the on-peak rating of the Conceptual capacity with an average 31 percent confidence factor.

This brings the expected capacity for demand and reserves to 239,500 MW in 2019. This is an expected 21,800 MW on-peak capacity increase from more than 63,000 MW of nameplate generator projects from the PJM and Midwest ISO generator interconnection queues.

The Other Existing Capacity resources are the existing generation resources within the RTOs or Region that is not included in the reserve margin calculations. Included in this category would be the derated portion of wind/variable resources, generating capacity that has not been studied for delivery within the RTO, and capacity located within the RTO that is not part of PJM committed capacity or Midwest ISO Capacity Resources. Also, units scheduled for maintenance and any existing generators that are inoperable are excluded from the Existing-Certain Capacity category when determining reserve margins.

The capacity represented by the Existing Capacity less the Other Existing Capacity is the category of Existing-Certain Capacity, which is comprised of the existing resources in PJM's Reliability Pricing Model (RPM) and the capacity resources in the Midwest ISO market.

The recent emphasis on renewable resources is increasing the amount of wind power capacity being added to systems in the Reliability*First* Region. In this assessment, the amount of available wind power capability included in the reserve calculations is less than the nameplate rating of the wind resources.

PJM uses a three year average of actual wind capability during the summer daily peak periods as the expected wind capability. Until three years of operating data is available for a specific wind project, a percentage of the capability is assigned for each missing year of data for that project. Some projects in the PJM generator interconnection queue use the formerly allowed 20 percent capability for wind, while newer projects use the current 13 percent capability factor.

In previous years, Midwest ISO allowed wind power providers to declare as a capacity resource, up to 20 percent of the nameplate capability. Beginning in 2010, the maximum wind capacity credit in the Midwest ISO is determined by using a technique that calculates the Equivalent Load Carrying Capacity for wind generation. The 2010 value is 8 percent of nameplate rating and is used in this assessment for each future wind project in the Midwest ISO.

Within Reliability*First* in 2010, there are 4,100 MW of existing nameplate wind turbine capacity with 500 MW being included as on-peak capacity for reserve requirements. Future-Planned wind turbines are projected to add 16,700 MW of nameplate capacity and 2,900 MW of on-peak capacity. Another 700 MW of on-peak wind capacity is projected from the Conceptual resources.

The current 5,800 MW of additional existing renewable resources, including pumped hydro, is projected to increase to 6,300 MW within the Region. The 700 MW of biomass (renewable) resources included in the Reliability*First* reserve margins in 2010 is projected to increase to 800 MW during the assessment period from the expected Future, Planned and Conceptual resources identified from the generator interconnection queues.

CAPACITY TRANSACTIONS ON PEAK

Firm power imports into the Reliability*First* Regional area are forecast to be 2,500 MW. Firm power exports are forecast to be 600 MW. These transactions all have firm transmission service. Therefore, net interchange is forecast to be a 1,900 MW import into Reliability*First,* which is included in the reserve margin calculations. There are no transactions using Liquidated Damage Contracts (LDC) or make-whole contracts.

TRANSMISSION

Plans within ReliabilityFirst for the next seven years include the addition of over 1,830 miles of high voltage transmission lines that will operate at 100 kV and above, as well as numerous new substations and transformers that are expected to enhance and strengthen the bulk power system. Most of the new additions are connections to new generators or substations. The Midwest ISO has identified many new projects as part of the Midwest ISO Transmission Expansion Plan (MTEP).[95]

Furthermore, several "backbone" transmission projects are planned within Reliability*Firs*t. PJM's Regional Transmission Expansion Plan (RTEP) has identified four major "backbone" projects, one from the 2006 RTEP and three additional ones from the PJM Board-approved 2007 RTEP.[96]

The Trans-Allegheny Interstate Line (TrAIL) project from the 2006 RTEP is a new 210-mile, 500 kV RFC-SERC interconnection and is scheduled for operation in 2011.[97] This project consists of a new 500 kV circuit from 502 Junction to Mt. Storm to Meadow Brook to Loudon. This project will relieve anticipated overloads and voltage problems in the Washington DC area, including anticipated overloads expected in 2011 on the existing 500 kV network. The four-year period before the existing facilities become overloaded presents a very challenging timeframe for the development, licensing, and construction of this project.

Three other PJM "backbone" projects from the 2007 RTEP are planned. One is the 130-mile, 500 kV circuit from Susquehanna to Lackawanna to Roseland will tie into the existing 500 kV network where multiple 230 and 115 kV circuits are tightly networked. This circuit then will continue to Roseland. Also, 500/230 kV transformers are proposed at Lackawana and Roseland substations. This circuit and

[95] See http://www.midwestmarket.org/publish/Folder/193f68_1118e81057f_-7f8e0a48324a?

[96] See http://www.pjm.com/documents/reports/rtep-report.aspx

[97] See http://www.aptrailinfo.com

transformer additions will create a strong link from generation sources in northeastern and north-central Pennsylvania into New Jersey. These facilities are expected to be in-service by June 2012.

The Potomac-Appalachian Transmission Highline (PATH) is the second "backbone" project, and consists of a 244-mile Amos to Bedington 765 kV line and a 92-mile, twin-circuit 500 kV line from Bedington to Kemptown.[98] This project will bring a strong source into the Kemptown, MD area by reducing the west-to-east power flow on the existing PJM 500 kV transmission paths and provide significant benefits to the constrained area of Washington DC and Baltimore. These facilities are expected to be in-service by June 1, 2015, at the latest.

The third "backbone" project is the Mid-Atlantic Power Pathway (MAPP), which consists of a new 190-mile 500 kV line beginning at Possum Point, VA and terminating at Salem, NJ.[99]

Phase Angle Regulators (PARs) on all major ties between northeastern PJM and southeastern New York help control unscheduled power flows through PJM resulting from non-PJM power transfers.

The original ITC*Transmission* Bunce Creek (B3N) Phase Angle Regulating transformer that failed in March 2003 has been replaced by two (series) Phase Angle Regulating transformers. Installation of the transformers was completed in December 2009. Energization of the transformers is dependent upon completion of protective system work in coordination with Hydro One, which is anticipated to be completed after the third quarter of 2010. Until ITC*Transmission* and Hydro One are authorized to begin operating the B3N Phase Angle Regulating transformers to control flows, the Phase Angle Regulating transformers on the L4D and L51D interconnections will be placed in the by-pass mode. The PAR on the Ontario- Michigan J5D interconnection near Windsor will be operated to assist in the management of local system congestion and for the optimization of power transfers. The Phase Angle Regulating transformers on the ITC*Transmission* - Hydro One interconnections will be used to control interconnection flows pending the receipt by ITC*Transmission* of an amended Presidential Permit from the U.S. Department of Energy and completion of various contractual and operational agreements between and among the respective Transmission Owners and Reliability Coordinators.

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

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[98] See http://www.pathtransmission.com/overview/default.asp

[99] See http://www.powerpathway.com/overview.html

The transmission system is expected to perform well over a wide range of operating conditions, provided that new facilities go into service as scheduled, and that transmission operators take appropriate action, as needed, to control power flows, reactive reserves and voltages.

The 2010 summer ERAG studies have identified significantly lower FCITC values in the Illinois-Wisconsin border area limited by the Zion- Pleasant Prairie 345 kV line when simulating west to east transfers. These lower FCITC values can be attributed to high north to south flows through the Wisconsin-Illinois eastern interface and a new generator connected to the Oak Creek substation. These lower FCITC values indicate that this line will most likely be a constraint during the summer of 2010 and in the future, as a recent 2014 summer study identified this same issue. PJM and Midwest ISO will need to manage flows on this constraint using their Market-to-Market procedures. A scope of potential work that would up-rate this line includes replacement of a wave trap at Zion and ground clearance improvement of approximately 3.5 miles of the line in Wisconsin. Presently, PJM and Midwest ISO are evaluating this constraint as part of the joint MISO-PJM Cross Border Top Congested Flowgate Study.

Operational Issues

During normal operations and for typical operations planning scenarios, there are transmission constraints within both the PJM and Midwest ISO areas of Reliability*First*. All of these constraints may be alleviated with generation redispatch or other operating plans/procedures with minimal reliability impact. Reliability*First* does not anticipate any significant impact on reliability from scheduled generating unit or transmission facility outages.

If peak demands are higher than expected, the Midwest ISO can call the Local Balancing Authorities to deploy Load Modifying Resources, however, the Local Balancing Authorities have the option to independently deploy Load Modifying Resources in light of other options that they may have. Demand Response Resources are dispatched in merit order through the Security Constrained Economic Dispatch. Midwest ISO can also use Emergency procedures if peak demands are higher than expected

Variability of forecasted demand is accounted for in the determination of the PJM Reserve Margin. The PJM forecast uses a Monte Carlo process that produces forecasts using all weather experienced over the last thirty-five years. The resulting 455 scenarios are rank ordered, with the median value being the base forecast. This extensive distribution of forecasts allows for estimation of peak load uncertainty at all probability levels of weather. PJM implements emergency procedures identified in the PJM Emergency Procedures Manual (M13), Section 2: Capacity Conditions.[100]

The amounts of distributed and variable generation are relatively small within PJM and are not expected to be a reliability concern. Midwest ISO plans to use variable dispatchable technology for the integration of variable resources in the future. There are currently no operational changes or concerns resulting from distributed resource integration.

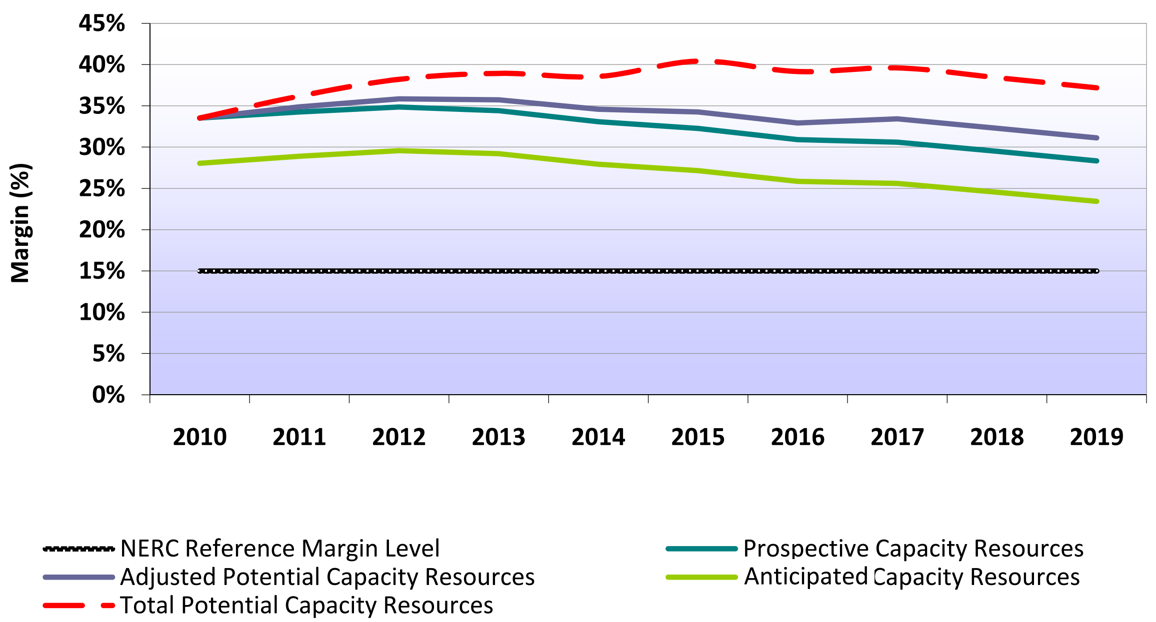
There is no anticipation for reliability concerns resulting from high-levels of Demand Response resources.

[100] http://www.pjm.com/~/media/documents/manuals/m13.ashx

RELIABILITY ASSESSMENT ANALYSIS

Analyses were conducted by the Midwest ISO LOLE Working Group and PJM at the end of 2009 or early in 2010 to satisfy the Reliability*First* requirement for Planning Coordinators to determine the reserve margin at which the Loss of Load Expectation (LOLE) is one day in ten years (0.1 day/year) on an annual basis for their planning area. Both PJM and Midwest ISO conduct their analyses over a planning year that runs June 1 through May 31 of the following year. These analyses include demand forecast uncertainty, outage schedules, the determination of transmission transfer capability, internal deliverability, CBM and other external emergency sources, treatment of operating reserves and other relevant factors when determining the probability of firm demand exceeding the available generating capacity. The assessment of resource adequacy is based on reserve requirements determined from these analyses.

Figure RFC-1: Summer Peak Reserve Margin Projections



The PJM Reserve Margin requirement for the 2010 and 2011 planning years is 15.5 percent. The Reserve Margin requirement for the 2012 planning year is 15.4 percent and for the 2013 through 2019 planning years the requirement is 15.3 percent. Similarly, the assessment of Midwest ISO resource adequacy is based on reserve requirements determined from its analysis. The Midwest ISO's reserve margin target for 2010 is 15.4 percent, and is used to assess each of the ten years in this assessment.

Reliability*First's* Resource Assessment Subcommittee believes that it is reasonable to assess the overall resource adequacy of the Reliability*First* Regional area by assessing the resource adequacy of the RTOs that operate within the Regional area. This is possible since the determination of each of the RTO reserve margin targets has been performed in a manner consistent with the requirements contained in Regional reliability standard BAL-502-RFC-002. The Resource Assessment Subcommittee believes that when Reliability*First* has determined that each RTO is projected to have sufficient resources to satisfy their respective reserve margin requirement, therefore the Reliability*First* area is projected to have adequate resources.

Deliverability of capacity between the RTOs is not addressed in this report. However, each of the reserve requirement studies conducted has assumed limited or no transfer capability between these two RTOs. Studies by the Eastern Interconnection Reliability Assessment Group indicate there is more than 4,000 MW of transfer capability between the two RTOs. The limited use of transfer capability in the reserve requirement studies provides a level of conservatism in this assessment.

It is important to note that the capacity resources identified as Existing-Certain in this assessment have been pre-certified by either PJM or Midwest ISO as able to be used within their RTO market area for the first year of the assessment period. This means that these resources are considered to be fully deliverable within and recallable by their respective markets. Both PJM and Midwest ISO include in the Existing-Certain category only those generator resources determined to satisfy their respective deliverability requirements. In both RTOs there are additional resources identified as Other Existing that may be available to serve load.

Reliability*First* has not performed any sensitivity analyses for high resource unavailability or high demand due to weather conditions. Any condition that increases Regional demand or generation resource unavailability beyond the forecast conditions in the assessment analysis will decrease overall resource reliability. However, over the ten year assessment period, extreme weather, fuel interruptions, and droughts are considered to be short term conditions that are not included when determining long term reliability targets. Over time, any adverse trends in forced outage rates will be factored into the analyses required by the Reliability*First* Planned Resource Adequacy Standard, and the reserve margin targets will reflect the need for higher reserves.

The PJM projected reserve margin for summer 2010 is 26.1 percent, which is in excess of the required reserve margin of 15.5 percent. The reserve margin reference for 2019 used in this assessment is 15.3 percent. The projected reserve margin for summer 2019 is 28.8 percent. The PJM RTO is projected to have adequate reserves through the assessment period.

The Midwest ISO projected reserve margin for summer 2010 is 25.5 percent, which is in excess of the required reserve margin of 15.4 percent. The projected reserve margin in 2019 is 16.5 percent. Using the 15.4 percent reserve margin requirement for 2010 as the reference reserve margin through 2019, the Midwest ISO is projected to have adequate reserves through the assessment period.

Since PJM and Midwest ISO are projected to have sufficient resources to satisfy their respective reserve margin requirements, Reliability*First* expects the Regional area to have adequate reserve margins throughout the entire assessment period.

Both Midwest ISO and PJM conduct comprehensive detailed generator load deliverability studies.[101] For more information on PJM deliverability, see Appendix E of the PJM Manual 14b.[102] Results of the PJM

[101] See: http://www.midwestmarket.org/page/Generator+Interconnection+Support+Documents

analysis are evaluated continuously as part of the normal PJM planning process and presented as part of the Transmission Expansion Advisory Committee (TEAC) meetings.[103] Neither Midwest ISO nor PJM have any deliverability concerns for this assessment period.

Reliability*First* members are ready to mitigate any fuel supply disruption that may occur. Some members may resort to fuel switching for those units with dual-fuel capability, if it becomes necessary to maintain reliable fuel supplies. Data available to Reliability*First* indicates that at least 10 percent of the Regional capacity has dual-fuel capability. Reliability*First* does not anticipate the need for any fuel switching in order to maintain reliable fuel supplies for the long-term assessment.

Since there currently are no adverse conditions affecting the resources within the Reliability*First* Region, this assessment assumes that any future adverse weather or fuel supply issues would be temporary in duration and limited in impact on resource availability, and will not affect the results of the reserve margin analysis. No other unusual operating conditions that could affect reliability are foreseen for this assessment period.

Transmission-limited and energy-only units are not considered in reliability analysis. They are modeled when performing generator interconnection studies to check short-circuit and dynamics performance.

Many states in the Reliability*First* Region have Renewable Portfolio Standards (RPS). It is up to the individual states to promote and provide incentives for renewable development.

PJM will assist with the planning studies to build transmission in order to bring the renewable generation into the PJM market. Variable resources are only counted partially for PJM resource adequacy studies. Both wind and solar initially use class average capacity factors, which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation, only historic performance over the peak period is used to determine the individual unit's capacity factor. In order to ensure reliable integration and operation of variable resources, PJM is investigating enhanced methods of regulation such as large utility-scale batteries.

There are large amounts of wind generation that must be integrated while meeting state Renewable Portfolio Standards within the Midwest ISO footprint. Due to the intermittent nature of wind, there is difficulty in predicting the wind capacity available on peak. Beginning in 2010, the maximum wind capacity credit in the Midwest ISO is determined by using a technique that calculates the Equivalent Load Carrying Capacity for wind generation. This method is linked to a Loss of Load Expectation. In this assessment the maximum on-peak capacity for future wind generation is 8 percent of nameplate rating. The Regional Generation Outlet Study is evaluating a number of other transmission expansions, some of

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[102] See: http://www.pjm.com/documents/~/media/documents/manuals/m14b.ashx

[103] See: http://www.pjm.com/committees-and-groups/committees/teac.aspx

which are expected to be in-service within the next ten years. Details on this study and transmission projects under evaluation can be found on the Midwest ISO website.[104]

Both PJM and Midwest ISO have processes in place to review the reliability impacts of planned retirements prior to the scheduled retirement date. Any potential reliability issues must first be mitigated before the scheduled retirement can occur. However, there are currently a number of potential environmental regulations, which may affect future unit retirement plans. Since current retirement schedules do not include the impact of these potential regulations, the potential impact on reliability has not been reviewed by PJM, Midwest ISO or Reliability*First*.

There are currently two automatic under voltage load shed (UVLS) schemes within Reliability*First*. One is located in the northern Ohio/western Pennsylvania area and the second is in the northern Illinois area. These schemes have the capability to automatically shed a combined total of about 1,800 MW and provide an effective method to prevent uncontrolled loss-of-load following extreme outages in those areas. There are currently no plans to install new UVLS within the Reliability*First* Region for this assessment period. Also, under frequency load shedding schemes (UFLS) within the Reliability*First* Region are expected to be able to shed the required amount of load during low frequency events.

Reliability*First* does not specifically study catastrophic events and is not aware of any specific studies. However, registered entities such as Transmission Planners may conduct their own extreme analyses.

Reliability*First* staff plus Midwest ISO, PJM, and the transmission planners within Reliability*First* all perform studies to analyze future transmission system configurations in accordance with the requirements in the NERC TPL standards. Results of the Reliability*First* studies are summarized in the Reliability*First* seasonal, near term, and long-term transmission assessment reports. These reports are posted on the ReliabilityFirst website.[105]

PJM performs voltage stability analysis (including voltage drop) as part of all planning studies and also as part of a periodic (every five minutes) analysis performed by the energy management system (EMS). Results are translated into thermal interface limits for operators to monitor. Transient stability studies are performed as needed and are part of the Regional Transmission Expansion Plan (RTEP) analysis.[106] Small signal analysis is performed as part of long-term studies, but not for seasonal assessments. Midwest ISO also performs transient stability analysis.

PJM and Midwest ISO companies are in the process of installing a large number of phasor measurement units (PMUs), also known as synchrophasors. PMUs are an integral element in modernizing the grid. These high-tech devices will monitor the state of the electrical grid 30 times per second, instead of the current once every four seconds, increasing the efficiency and reliability of power delivery. The data is also GPS time-stamped. This allows the data to be 'synchronized' which enables enhanced grid visualization, operational awareness, stability monitoring, state estimation, and after-the-fact analysis.

[104] See: http://www.midwestmarket.org/page/Renewable%20Energy%20Study

[105] See: http://www.rfirst.org/Reliability/ReliabilityHome.aspx

[106] See http://www.pjm.com/documents/reports/rtep-report.aspx

Smart Grid projects are not expected to have a detrimental effect on reliability.

There are no anticipated project slow-downs, deferrals or cancellations which may impact reliability in the Reliability*First* footprint.

OTHER REGION-SPECIFIC ISSUES

Reliability*First* has no additional reliability concerns for this long-term assessment.

REGION DESCRIPTION

ReliabilityFirst currently consists of 48 Regular Members, 22 Associate Members, and four Adjunct Members operating within 3 NERC Balancing Authorities (Midwest ISO, OVEC, and PJM), which includes over 350 owners, users, and operators of the bulk-power system. They serve the electrical requirements of more than 72 million people in a 238,000 square-mile 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. The ReliabilityFirst area demand is primarily summer peaking. Additional details are available on the ReliabilityFirst website.[107]

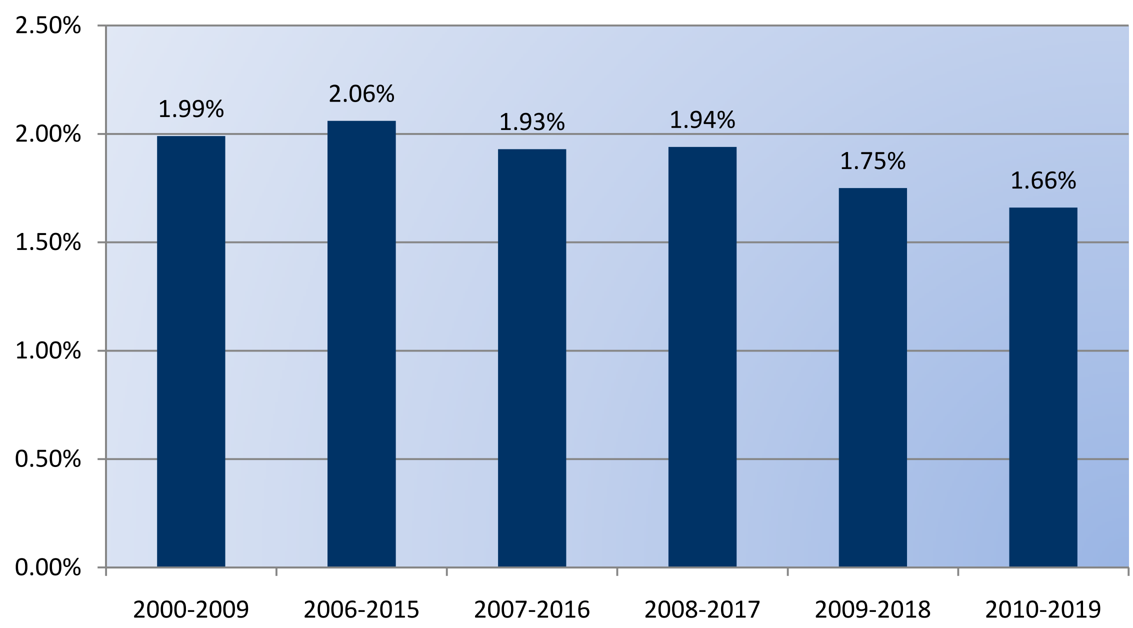
[107] See http://www.rfirst.org

SERC

Executive Summary

The aggregate total internal summer peak demand for the utilities within the SERC Region is projected to increase from 199,619 MW in 2010 to 234,673 MW in 2019. The Total Internal Demand for 2010 summer is 1,749 MW (0.9 percent) lower than the forecast 2009 summer peak of 201,368 MW and the actual 2009 summer peak was 186,804 MW. Net internal demand for 2018 is forecasted to be 224,241 MW; 4,621 MW (2.0 percent) lower than the 228,862 MW Net Internal Demand forecasted from last year's LTRA, indicating a slowdown of growth. SERC Figure 1 shows the reduction in SERC's Net Internal Demand growth rates[108] over the past five LTRA reporting periods along with the actual Net Internal Demand growth rate for the past ten years. The LTRA projections are based on average historical summer weather and are the sum of noncoincident forecast data reported by utilities in the SERC Region. Some entities have lowered their forecasts as compared to previous period forecasts due to the current economic recession. There were no significant changes in weather assumptions but the economic recession caused a near-term drop in demand. A rebound in demand growth is projected in the near-term (LTRA data for 2010-2014) and then in the long-term (LTRA data for 2015-2019) time horizon growth rates will trend much lower.

Figure SERC-1: SERC Net Internal Demand Growth Rates

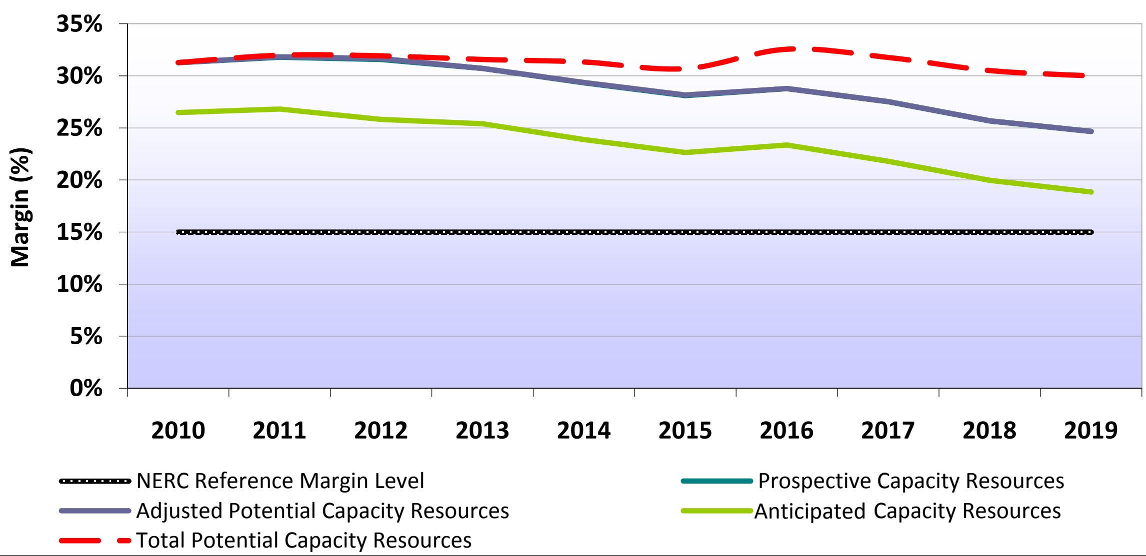


[108] SERC growth rates are calculated using the log-linear least squares growth rate method, which is least likely to be biased by a randomly high or low beginning or ending year.

The SERC Region restructured its data collection process to collect data at the unit level in 2010. Looking forward, fluctuations in capacity increases and decreases experienced within the SERC Region should be more clearly delineated. The transition to unit-level reporting has resolved a few instances of double counting. For 2010, utility data shows a total of 245,546 MW of Existing-Certain capacity which represents a net increase of 2,249 MW or 0.9 percent in existing capacity as reported in 2009. Existing-Certain is a category that remains in flux as Existing-Certain units can become inoperable or be reclassified as Existing-Other if the unit has no firm contract in place. The classification of generation capacity throughout the assessment period has become more complicated and volatile with numerous independent power producers in the markets that have no long-term contracts to serve demand. It is anticipated that 22,863 MW of Future-Planned and Future-Other capacity will be placed in service by 2019. Entities anticipate approximately 1,279 MW of additional variable resources during the time period and no significant unit retirements are expected.

Deliverable capacity resources within the Region are forecast to be able to supply the projected firm demand with adequate margin throughout the period. The projected long-term reserve margins under various definitions are reflected in SERC Figure 2.

Figure SERC-2: Summer Peak Reserve Margin Projections



Reported Future-Planned and Existing capacity, along with the necessary transmission system upgrades to ensure the deliverability of the capacity, will satisfy reserve margin needs through 2019. The outcome in terms of resource adequacy is highly dependent on regulatory support for generation expansion plans, new state, local and federal environmental regulations impacting operation of existing generating resources, and state and local environmental and siting process regulations as they influence the development of new generating resources.

7,503 MW of the anticipated Future-Planned and Future-Other capacity is identified as nuclear generation in this report. In 2006, the entities within SERC began to report new nuclear units in the long-term planning horizon. Interest in new nuclear construction is driven by the increasing need for base-load generation, increasing environmental constraints and potential controls on carbon emissions, volatility in natural gas prices and increasing support for nuclear energy from the public and policy makers. Incentives in the Energy Policy Acts of 1992 and 2005 were designed to reduce licensing risks and offset higher initial costs, ensuring that the first new nuclear plants will be competitive and economically viable. In addition, the states of Georgia, South Carolina, and Virginia have passed legislation in the past few years encouraging new plant construction by providing higher assurance of investment recovery.[109] The Vogtle plant's early site permit was approved in August 2009[110] and the Watts Bar plant's new unit is scheduled to open by 2013.[111]

Entities in many of SERC's subregions have reported they are recovering from the current economic recession that has affected both load growth and capacity projections. Utilities continue to minimize reliability concerns in the near-term by increased monitoring of the system and more rigorous operational planning studies. With projected additions and transmission enhancements within SERC's subregions, capacity is considered adequate to meet the load, and the transmission system is monitored continuously to address concerns. Additional transmission improvements and investments are planned to be in service for the forecast period with the intent of maintaining system reliability.

Spending for transmission improvement is generally higher than reported in previous years. SERC Region utilities spent approximately $1.9 billion in new transmission lines and system upgrades (transmission lines 100 kV and above and transmission substations with a low-side voltage of 100 kV and above) since 2009. Projected investments over the 2010 to 2014 time period total $11.9 billion; $2.4 billion in 2010, $2.3 billion in 2011, $2.4 billion in 2012, $2.4 billion in 2013 and $2.4 billion in 2014.

Overall, there are no transmission constraints that significantly impact reliability of the utilities in the SERC Region during the ten-year assessment period. In subregional sections of this assessment, discussions for certain utilities indicate a few situations, which require monitoring or operating procedures, but no significant reliability issues.

Results from the ERAG (Eastern Interconnection Reliability Assessment Group)-sponsored 2010 Summer MRO-RFC-SERC West-SPP Inter-Regional Transmission System Assessment indicate an easing of transmission transfer issues between the Delta subregion and some neighboring Regions involved in the study. Because of planned upgrades on the Delta-SPP interface scheduled for completion prior to 2010 summer, some facilities will no longer limit Regional and subregional transfers to "zero". Details of these upgrades are provided in the Delta subregion section of this report. In addition, the Arkansas Nuclear One – Russellville North 161 kV line upgrade has a completion date of June 2010. This project will mitigate potential loading on certain transmission facilities that are located on the interface between Entergy and neighboring SPP systems.

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[109] Nuclear Energy Institute(NEI), http://www.nei.org/index.asp?catnum=4&catid=1032

[110] U.S. Nuclear Regulatory Commission, http://www.nrc.gov/reactors/new-reactors/new-licensing-files/consolidated-col-schedule.pdf

[111] Cleveland Daily Banner, http://www.clevelandbanner.com/view/full_story/8930774/article-TVA--CU-facing-cost--power-demand-challenges?instance=homefirstleft

The transmission systems in SERC are expected to have adequate delivery capacity to support forecast demand, 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-002-0) and the member companies' planning criteria relating to transmission system performance. The 2010 summer studies show that various operating guides are in place in the event that planned reconductoring projects, facility upgrades and new transmission line additions within various subregions are not completed on time. Entities continue to evaluate the situations through ongoing operating procedures with the intent to maintain reliability on the system.

Entities do not anticipate significant operational problems or constraints during the assessment period. Operational planning studies are performed regularly or as needed. Individually, entities mitigate concerns that occur on the system to avoid reliability impacts. Details on specific study areas can be found in the subregional sections of this report.

To minimize reliability concerns within the Region, entities engage in individual assessment studies and participate in a host of committees designed to perform system studies and address industry issues that are important to reliability. Assessment studies include steady-state power flow studies, dynamics/stability studies, and transmission transfer capabilities both internal and external to SERC. The Region relies on the SERC NTSG (Near-term Study Group), SERC LTSG (Long-term Study Group), SERC DSG (Dynamics Study Group) and SERC SCDWG (Short Circuit Database Working Group) to coordinate these studies in order to ensure the system is adequate for projected peak demands. Coordinated studies with neighboring Regions and SERC subregions through the ERAG indicate that transmission transfer capability will be adequate on all interfaces to support reliable operations for the summer assessment period. These processes and studies are discussed in more detail within the subregion sections.

Region Description

The SERC Region is a summer-peaking Region covering all or portions of 16 central and southeastern states[112]serving a population of over 68 million. Owners, operators, and users of the bulk power system in these states cover an area of approximately 560,000 square miles. SERC is a nonprofit corporation responsible for promoting and maintaining the reliability, adequacy, and critical infrastructure of the bulk power supply system. SERC membership includes 63 member-entities consisting of publicly-owned (federal, municipal and cooperative), and investor-owned operations. In the SERC Region, there are 32 balancing authorities within a total of 200 other registered entities.

SERC Reliability Corporation serves as a Regional Entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the SERC Region. The SERC Region is divided geographically into five subregions that are identified as Central, Delta, Gateway, Southeastern, and VACAR. Additional information can be found on the SERC Web site (http://www.serc1.org).

[112] Alabama, Arkansas, Florida, Georgia, Iowa, Illinois, Kentucky, Louisiana, Mississippi, Missouri, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia

CENTRAL SUBREGION

DEMAND

The 2010 summer aggregate Total Internal Demand forecast for the utilities in the Central subregion is 42,364 MW and the forecast for 2019 is 49,951 MW. This year's forecast CAGR (compound annual growth rate) for 2010-2019 is 1.82 percent. This is higher than last year's forecast growth rate of 1.52 percent.[113]

The 2010-2019 demand forecast is based on normal weather conditions and economic data for the subregion population, forecast demographics for the area, employment, energy exports, and gross Regional product increases and decreases. No significant changes have been made to the 2010-2019 weather and economic assumptions.

As with other subregions in SERC, strong emphasis is placed on Energy Efficiency. TVA and participating distributors of TVA power currently offer the following Energy Efficiency programs across the residential, commercial, and industrial markets:

- **New Homes** – Promotes all-electric, energy-efficient new homes. All homes built must meet a minimum rating in overall Energy Efficiency.
- **Heat Pump** – Promotes the installation of high efficiency heat pumps in homes and small businesses.
- **New Manufactured Homes** – Promotes the installation of high efficiency 13 SEER[114] heat pumps in new manufactured homes and currently has over 40 percent of the market share in the Valley.
- **Do-It-Yourself Home Energy Evaluation** – This program allows homeowners to receive a free Energy Efficiency kit from TVA after completing an online or paper home-energy survey. Residents also receive personalized reports on their home's annual energy usage and energy-saving recommendations.
- **In-Home Energy Evaluation Program** – This program offers financing options and incentives to help homeowners make investments in significant Energy Efficiency improvements identified through onsite evaluation by an Energy Efficiency professional.
- **Commercial Efficiency Advice and Incentives Program** – This program offers businesses an opportunity to receive an energy assessment of their facilities to help them identify energy-saving opportunities. Financial incentives are also available for projects that help reduce power consumption during TVA's peak period.
- **Major Industrial Program** – This program encourages reductions in electric energy intensity in large industrial facilities that have a contract demand greater than five megawatts. Financial incentives are available for projects' resulting in reductions during TVA's peak period.

TVA is working with power distributors to develop additional programs, including offerings targeted at residential HVAC maintenance, small business lighting, commercial building recommissioning, and prescriptive energy-efficient equipment incentives for industrial and commercial end-users.

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[113] Note that this section of last year's report for Central gave values for Net Internal Demand, not Total Internal Demand.

[114] Definition for SEER: http://www.inspectapedia.com/aircond/aircond04.htm

TVA is employing a third-party evaluator to review the performance of all programs on an ongoing basis to assure the programs continue to achieve the expected levels of energy and demand reductions.

The primary sources of Demand Response for TVA are interruptible loads obtained through a Demand Response aggregator and interruptible loads obtained directly through pricing products. The aggregator provides loads through contracts with end-use customers to curtail their loads within 30 minutes of being notified of an event. The aggregator solicits participation, contracts with the consumer, installs remote metering capable of providing 5-minute interval information available to both the utility and the consumer, notifies the consumer of the event call upon notification from the utility, and monitors the performance of the consumers under contract to ensure compliance through coaching during the event. The aggregator bears financial consequence for ensuring the delivery of the contracted amount and, therefore, typically oversubscribes consumer participation to assure full delivery. Interruptible pricing products focus on direct signals to participating consumers who, depending on the product selected, agree to reduce load by the contracted amount within either 5 or 60 minutes of notification. Verification of results from the aggregator program are available in near-real time while the TVA pricing products require review of billing data to confirm impacts achieved at the end of each billing cycle. Initiation of reductions from pricing products is currently based on reliability while reductions through the aggregator are for economics or reliability. TVA is also beginning development of additional Demand Response resources based on direct load control of air conditioning and water heaters as well as conservation voltage regulation of distribution feeders.

Entities within this subregion reported they do not have reliability portfolio standards with which they must comply.

To assess variability, utilities within the subregion use the demand forecast assumptions mentioned above to develop models for extreme peaks and demand models to predict variance. Models take into consideration extreme temperatures, economic and price uncertainty. No significant changes to forecasting methods have been reported for the assessment period.

Generation

Utilities in the Central subregion expect to have the following capacity on-peak. Capacity in the categories of Existing (Certain, Other and Inoperable), Future (Planned and Other) and Conceptual are expected to help meet demand during this time period.

Table SERC-1: Central Capacity Breakdown		
Capacity type	2010 (MW)	2019 (MW)
Existing-Certain	49,355	50,326
Nuclear	6,671	6,671
Hydro/Pumped Storage	5,642	6,562
Coal	24,731	24,782
Oil/Gas/Dual Fuel	12,265	12,265
Other/Unknown	27	27
Solar	0	0
Biomass	17	17
Wind	2	2
Existing-Other	480	480
Existing-Inoperable	71	0
Future-Planned	166	3,201
Future-Other	0	0
Conceptual	0	714
Wind	0	0
Solar	0	0
Hydro/Pumped Storage	0	0
Biomass	0	0

The wind resource in the Central subregion is generally unsuitable for large scale wind generation. There is 29 MW of wind turbines are installed within the TVA system at Buffalo Mountain, Tennessee but are reported in the above generation totals as 2 MW of capacity on-peak. TVA has initiated a power purchase agreement program with RFPs (requests for proposals) for up to 2,000 MW from renewable sources, expected to be primarily wind, but deliverability and the contribution to capacity have yet to be confirmed. To address variable capacity calculations, subregional utilities either have no variable capacity or do not consider them toward capacity requirements.

For reliability analysis/reserve margin calculations, entities within this subregion take into account existing resources and may use an RFP process for forward capacity markets or use firm contract purchases (both generation and transmission) toward firm capacity. Most entities in the subregion do not apply a confidence factor to Conceptual resources. Instead, entities may use risk analysis and scenario planning studies to identify potential resource adequacy issues. Resource adequacy may be assessed both with and without Conceptual resources to identify the magnitude of risk exposure and the lead time needed to ensure the necessary commitments to acquire or construct resources to maintain reliability. Short-term capacity planning (three to five years out) is used to focus on market options that might be available to replace Conceptual resources identified by long-range capacity expansion planning studies.

Capacity Transactions on Peak

Central subregion utilities have reported the following imports and exports for the ten-year reporting period. The majority of these exports/imports are backed by firm contracts for both generation and transmission. It was not reported if import assumptions are based on partial path reservations. These reports have been included in the aggregate reserve margin for utilities in the subregion.

Table SERC-2: Central Purchases and Sales

Transaction type	2010 Summer (MW)	2014 summer (MW)	2019 summer (MW)
Firm imports (external subregion)	2,541	1,647	1,663
Firm exports (external subregion)	495	504	504
Expected imports (external subregion)	194	202	212
Expected exports (external subregion)	0	0	0
Provisional imports (external subregion)	0	0	0
Provisional exports (external subregion)	0	0	0

Transmission

Due to problems obtaining right-of-way, a further in-service-date delay (after 2010/2011 winter) of the new Mill Creek to Hardin 345kV line may cause a variety of contingent overloads. This may limit generator output to local Regional load. In the event that that the in-service date is delayed, operating guides have been prepared to minimize potential reliability impacts on the system. The Mill Creek to Hardin 345kV installation is currently scheduled for completion in June 2010. Outside of this project, there are no other potential reliability concerns and impacts with target transmission in-service dates around the subregion.

Heavy north-to-south flows and external constraints continue to impact the ability to import power. The recent upgrade of the Coleman to Newtonville 161 kV interconnection and a planned Vectren 345 kV project may help alleviate the constraints (Projects are located in the MISO area of the RFC Region). Entities continue to evaluate the transmission system to identify any future constraints that could significantly impact reliability in the future. These future constraints and proposed solutions are published annually in plans similar to the Transmission Expansion Plan (Independent Transmission Organization (SPP)). System conditions may at times dictate local area generation redispatch to alleviate anticipated next contingency overloads. Companies in these situations may invoke NERC TLR (transmission loading relief) procedures to control scenarios that are not easily remedied by a local redispatch. Recent assessments have not shown significant changes since the 2009 assessment. Overall, no other constraints to the bulk power system are expected to impact reliability during the assessment period.

Entities within the Central subregion continue to evaluate and consider new technologies that can be used to improve bulk power system reliability. The deployment of smart grid technologies is being assessed in consultation with power distributors, and some distributors are implementing programs. No significant substation equipment other than capacitor banks was added since the 2009 summer season.

Operational Issues

Other than scheduled individual planned outages, there are no existing or potential systemic outages that negatively impact reliability anticipated within the Central subregion for the next 10 years.

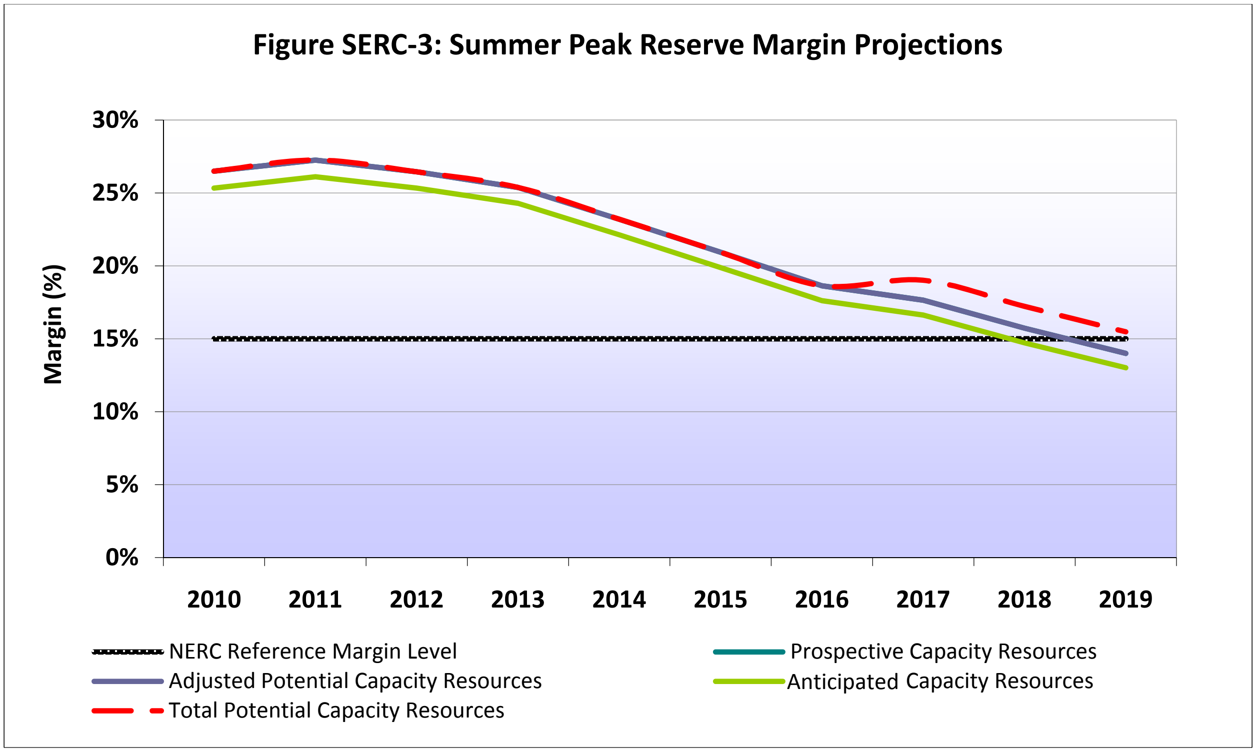
To address operational measures that are available if peak demands are higher than forecast, utilities within the subregion perform studies based on both normal and extreme projected peak conditions. No unique problems from recent studies have been observed. Monthly, weekly, and daily operational planning efforts take demand and unit availability into consideration. This helps to address any inadequacies and mitigate their risks. Entities also expect to use various operational measures during unexpected high peak demands. Some of these measures are day-ahead and hourly spot purchases, interruptible load, and DSM (Demand-Side Management) measures. As a last-step measure, entities have the ability to shed firm load to maintain the integrity of the interconnected power system. Various emergency operations plans, processes and procedures are in place to ensure balance from resource-to-load and reserve obligations.

There are also no environmental or regulatory restrictions that currently affect system reliability. The majority of the entities within the subregion have not integrated variable resources on their systems. However, wind contracts in place for the assessment period are not anticipated to be significant enough to cause operational changes or concerns. Also, due to limited Demand Response in the subregion, reliability concerns from high levels of Demand Response resources are not a concern.

Resource Assessment Analysis

Projected net-capacity reserve margins for utilities in the Central subregion as reported between the years 2010-2019 are from 13.0 percent to 26.1 percent over the ten-year period (see Figure Central-1). There is no subregional, Regional, state or provincial reserve margin requirement for this subregion.

Entities within the Central subregion do not adhere to any Regional/subregional targets or reserve margin criteria. However, some individual entity criteria are established based on the balancing authority's criteria such as most severe single contingency, cost of unserved energy, unit availability, import availability/capability, load forecast, and loss-of-load probability studies (such as 1 day in 10 years). TVA has recently implemented new study capabilities and reviewed its criteria for reserve margin based on a completed detailed probabilistic assessment that will be repeated annually.



Resource adequacy studies around the subregion show that there is sufficient capacity to adequately supply the load. Variables within the studies are based on unit availability, import availability/capability, load forecast, and weather assumptions. The intent of these studies is to identify limitations or constraints that may impact seasonal adequacy, inform necessary decisions relative to resource acquisitions and project development timelines to maintain system reliability. If resource inadequacies cause the reserves to be reduced below the desired level, companies within the subregion can make use of purchases from the short-term markets in the near-term and various ownership options in the long-term, as necessary. Recent studies show that by the use of these procedures and resources, new capacity will need to be added to various systems within the ten-year period. However, reported existing and projected capacity is expected to be sufficient to meet demand during this time period to maintain reliability.

On average for the ten-year period, 50,206 MW of internal resources and 1,885 MW of capacity transactions which account for internal resources of non-reporting parties and for external resources were reported demand during the time period. These resources are considered able to meet the criteria or target reserve margin level for 2010 summer.

Overall, utilities within the subregion are not relying on short-term outside purchases or transfers from other subregions or Regions to meet demand requirements. To meet long-term demand needs, entities explore options to build capacity, use existing capacity and expand current capacity or contract for new capacity. The majority of the entities in the subregion are members of reserve sharing groups with other neighboring entities such as PJM, Midwest ISO or TCRSG (TEE Contingency Reserve Sharing Group). Both long-term and short-term reserve margin requirements are treated the same.

In order to ensure fuel delivery in the event of fuel interruptions, the practice of having a diverse portfolio of suppliers, including the purchase of high-sulfur coal from the Northern and Central Appalachia coal Region (West Virginia, East Kentucky), Ohio and the Illinois Basin (West Kentucky, Indiana, Illinois) is common within the subregion. Fuel departments typically monitor supply conditions on a daily basis through review of receipts and coal burns and interact daily with both coal and transportation suppliers to review situations and foreseeable interruptions. Any identifiable interruptions are assessed with regard to current and desired inventory levels. Because coal is purchased from different Regions, it is expected to move upstream and downstream to various plants. Some plants have the ability to re-route deliveries between them. Some stations having coal delivered by rail can also use trucks to supplement deliveries. Utilities have reported that they maintain fuel reserve targets greater than 30 days of on-site coal inventory. Fuel supplies are adequate and anticipated to be readily available for the assessment period. Multiple contracts are in place for local coal from area mines. In the event of extended drought or forced outages, entities report that they will exercise options to make off-system purchases to meet demand.

Utilities within the Central subregion do not typically include energy-only or transmission-limited resources in their adequacy assessments. If entities see that resources are not available, they may plan on day-ahead and hourly spot-purchases as needed to make up any shortfalls in the system.

There are currently no RPSs or other mandates that impact variable renewable resources in resource adequacy processes. Some entities include small amounts of variable renewable resources in adequacy assessments based on historical experience. These resources are mixed with the dependable capacity values of those resources at the time of the system peak. Variable renewable resources from outside individual entity systems may be treated as purchased power resources and are included only if firm transmission service is available. If transmission service is firm, the dependable capacity of these resources is based on the projected capacity value coincident with the system peak.

Some entities within the subregion do not consider any Demand Response in resource adequacy assessments due to the minimal effects on the system. However, other entities consider Demand Response programs such as interruptible and direct load control as a resource. These programs create a load reduction and therefore impact reserves carried for the system. Other entities include the contribution of Demand Response programs in their long-range capacity planning studies based on analysis of the particular program impacts, historical trends of Demand Response effectiveness, and system cost-effectiveness criteria. This analysis helps to set a dependable capacity value of Demand Response for use in summer-peak adequacy assessments. Scenario planning is also employed to evaluate the impact on system reliability for differing assumptions of Demand Response effectiveness.

No generating unit retirements are planned for the next 10 years that could have a significant impact on reliability. Entities conduct scenario-planning studies to assess the impact on system reliability and adequacy for various assumptions of possible unit retirements that might occur during the planning window. The results of those studies are used to inform the annual planning process and provide valuable input to ongoing development of generating fleet strategic plans.

No additional UVLS (under voltage load shedding) schemes are planned for installation during the assessment period. TVA has UVLS protection schemes installed in two areas of the system for the purpose of limiting a potential wider area under-voltage event. The non-coincident peak demand served from the substations equipped with UVLS totals approximately 450 MW. No SPS (Special Protection System) or remedial action schemes are presently used and TVA's planning policy is that none will be installed in lieu of transmission reinforcements.

Currently, plans to participate in drills are in place on entity systems to ensure that operators are trained and properly prepared for catastrophic events. The transmission planning process prepares for the loss of up to all units at any given generating station as part of seasonal assessments. They disseminate that information to system operations for additional planning procedures. Entities also rely on reserve sharing, PSEs (purchasing and selling entities) and coordination with balancing authorities through capacity and energy emergency plans. Planned unit maintenance outages or de-rates may be delayed or cancelled in the event of a significant loss in capacity. If these efforts are not sufficient, then voluntary load shedding and energy emergency criteria will be enacted. In planning their systems, entities may use risk analysis and stochastic processes to identify the contingencies that most impact their resource adequacy over the long-term. Specific outage events are not modeled in that analysis, but may be considered during sensitivity studies as part of the annual capacity planning effort. If resource inadequacies (such as catastrophic events) cause the reserve margin to be reduced, entities then anticipate the use of purchases from the short-term markets as a necessary addition to appropriate operational actions to ensure system reliability.

Companies within the subregion maintain individual criteria to address any problems with stability issues. Recent stability studies identified no issues that could affect the system reliability during the 2010 summer season. Criteria for dynamic reactive requirements are addressed on an individual company basis. Utilities employ study methodologies designed to assess dynamic reactive margins. Programs such as Reactive Monitoring Systems give operators an indication of reactive reserves within defined zones on the system.

Voltage stability margins are also implemented by utilities on an individual basis. Utilities generally follow the procedure of making sure that the steady-state operating point is at least five percent below the voltage collapse point at all times to maintain voltage stability. Studies are performed on peak demand cases to verify system stability margins. Other utilities follow guidelines to ensure that voltage stability will be maintained via Q-V analysis[115].

Entities within the Central subregion continue to evaluate and consider new technologies that can be used to improve bulk power system reliability. The deployment of smart grid technologies is being

[115] Q-V analysis is a common graphical analysis used to measure voltage stability at load buses by observations in the VAriations of VARs and MWs. This method is used to help utilities define measurements of stable operation and measure instability in the event of a disturbance on the system. (http://eeeic.eu/proc/papers/11.pdf

assessed in consultation with power distributors and some distributors are implementing programs. However, no new transmission level technologies have been installed since the 2009 summer.

A new 25 mile, 161 kV transmission line that is planned for Marion Power Plant to Carrier Mills is already several years behind schedule due to right-of-way issues. The remaining right-of-way issues will be resolved through a condemnation process. This delay has no impact on the reliability of the bulk power system, but can negatively impact neighboring transmission systems. At this time, there are only minor delays in projects that are scheduled for completion in the next year. The impacts of these delays will be mitigated as needed.

Even though entities within the Central subregion anticipate no major impacts on reliability for the assessment period, they continue to analyze and improve the system through continuous planning processes. Entities are looking into increasing the capacity ratings of transformers, installing CTs, upgrading transmission lines, replacing equipment, etc. As concerns are identified, real-time operating guides will be developed with the appropriate reliability coordinators and system enhancements or upgrades will be considered as appropriate.

SUBREGION DESCRIPTION

The geographical coverage of the Central subregion includes most of Tennessee and Kentucky, northern Alabama, northeastern Mississippi, and small portions of Georgia, North Carolina, and Virginia.

DELTA SUBREGION

DEMAND

The 2010 summer aggregate Total Internal Demand forecast for the utilities in the Delta subregion is 27,945 MW and the forecast for 2019 is 32,266 MW. This year's forecast CAGR for 2010 to 2019 is 1.55 percent. This is lower than last year's forecast growth rate of 1.63 percent. Growth rates declined at a slower rate and are attributed to customer usage patterns, economic conditions and changes in commercial/industrial/wholesale load. The forecast assumes ten-year normal weather and a gradual economic recovery. Forecasts are also based on a forecast study, which produced new econometrically-based forecasts of commercial/industrial load, future economic/demographic conditions and historical data. Cooperatives assess the likelihood of new distribution loads and a probability adjustment is incorporated into the cooperative's load forecast.

Utilities within the Delta subregion are implementing Energy Efficiency programs to distribution cooperatives and the residential sector. A variety of programs ranging from home energy audits, CFL lighting, Energy Star rated washing machines, and dishwashers to Energy Star rated heat pumps and air conditioners have been added into company portfolios. Utilities plan to offer these types of programs as long as they are determined to be cost-effective. Annual M&V (measurement and verification) programs measure energy savings and costs for each of the Energy Efficiency programs. Information from these M&V programs will be used to fine tune Energy Efficiency programs and to determine each program's cost effectiveness. The current forecast includes Energy Efficiency programs that have received regulatory approval. As programs advance, they will be incorporated into retail sales and load forecasts.

DSM programs among the utilities in the subregion include interruptible load programs for larger customers, direct-control load management programs for agricultural customers and a range of conservation/load management programs for all customer segments. There have not been any significant changes in the amount and availability of load management, and interruptible demand in recent years. Measurements and verification for interruptible Demand Response programs for larger customers are conducted on a customer-by-customer basis. This includes an annual review of customer information and firm load requirements. Compliance is determined by a review of customer load data as related to the terms and conditions of the electric rate schedule. In addition, because significant amounts of these resources are not expected during the time period, they are not used for meeting renewal portfolio standards.

Load scenarios for outage planning purposes are developed regularly to address variability issues in demand. These load scenarios include load forecasts based on high and low scenarios for energy sales, and scenarios for alternative capacity factors. Load scenarios for load-flow analyses in transmission planning are also developed and posted to OASIS[116]. Some of the scenarios developed within the subregion were reported to be based on an assumption of extreme weather, which were more severe than the forecast peaking conditions but less severe than the most severe conditions found in the historical records. Special analyses are performed to examine forecast peak loads associated with cold

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[116] Open Access Same-Time Information System

fronts, ice storms, hurricanes, and heat waves. These analyses are performed on an ad-hoc basis and may be conducted for various parts of the subregion.

Other entities use planning procedures to produce projected forecasts, which are based on normal weather/economic and demographic conditions. Optimistic/pessimistic economic and demographic conditions with normal weather and severe and mild weather are also accounted for in the forecast. Forecasts are produced on a regular basis to capture significant conditions annually.

Generation

Companies within the Delta subregion expect to have the following capacity on peak. Capacity in the categories of Existing (Certain, Other and Inoperable), Future (Planned and Other) and Conceptual are expected to help meet demand during this time period.

Table SERC-3: Delta Capacity Breakdown

Capacity Type	2010 (MW)	2019 (MW)
Existing-Certain	40,172	37,496
Nuclear	5,251	5,251
Hydro/Pumped Storage	262	262
Coal	9,080	9,080
Oil/Gas/Dual Fuel	25,579	22,903
Other/Unknown	0	0
Solar	0	0
Biomass	0	0
Wind	0	0
Existing-Other	3,752	7,510
Existing-Inoperable	1,378	1,378
Future-Planned	0	729
Future-Other	0	0
Conceptual	0	4,005
Wind	0	0
Solar	0	0
Hydro	0	500
Biomass	0	380

Resources are evaluated based on capability to meet required reliability requirements and economics. Future-Planned capacity additions are built into company portfolios; however variable capacity is not counted as capacity to meet reliability requirements.

Resources identified for the purpose of reliability studies and reserve margin calculations include Existing owned and contracted resources as well as Conceptual self-build projects and Existing resources operating in forward capacity markets. Energy plants that can be dispatched with reliable, flexible fuel supply are considered for capacity resources. These include fossil fuel plants and hydro but do not include variable resources. Some entities have a policy not to rely on energy markets for capacity and maintain capacity margins mostly from internal resources. However, other entities also factor in energy-supplier review forecast information and historical reserve allocation as a participant in the SPP (Southwest Power Pool) Reserve Sharing Group. These forecasts help to make decisions regarding the amount of capacity needed for the upcoming year.

In addition, no reported adjustments have been made to Conceptual resources for the time period. Conceptual resources for planning capacity are considered by some entities to be those resources that are permitted and constructed given the known market for capital, resources, and labor. These Conceptual resources are viable, realistic options that can be made available using prudent business practices to meet a capacity requirement.

Capacity Transactions on Peak

Delta subregion utilities expect the following imports and exports for the ten-year period 2010-2019. These imports and exports have been accounted for in the reserve margin calculations for the subregion.

Table SERC-4: Delta Purchases and Sales

Transaction Type	2010 Summer (MW)	2014 Summer (MW)	2019 Summer (MW)
Firm imports (external subregion)	2,632	1,855	1,229
Firm exports (external subregion)	3,340	2,240	2,240
Expected imports (external subregion)	0	0	50
Expected exports (external subregion)	0	0	0
Provisional imports (external subregion)	0	0	0
Provisional exports (external subregion)	0	0	0

All contracts for these imports/exports are backed by firm transmission and are tied to specific generators. No imports/exports have been reported to be based on partial path reservations. For the assessment period, there are no liquidated damage contracts and associated “make whole” contracts.

The subregion is dependent on certain imports, transfers, or contracts to meet the demands of its load. Most entities within Delta are members of the SPP Reserve Sharing Group. Group participants within SPP generally transfer reserves into the subregion to either replace generation (largest contingency) or supply generation to the subregion. These reserves are not relied upon in the resource adequacy assessment, or for capacity, or reserve margins. System operators generally coordinate the scheduling and transmitting of the reserves.

Transmission

Entities within Delta do not expect any delays in meeting in-service dates for projects scheduled for the time period. There are no significant transmission facility outages that impact bulk power system reliability. Prior to approval of any proposed maintenance outages, studies would be completed to identify impacts on reliability.

No transmission constraints are expected to significantly impact bulk system reliability for the period. Companies within the subregion regularly participate in NTSG seasonal reliability studies. The NTSG 2010 Summer Reliability Study preliminary results indicate that imports into the subregion can be limited due to the McAdams 500/230 kV autotransformer for the loss of the McAdams - Lakeover 500 kV flowgate. This flowgate, which is located near a 500 kV tie within the Central subregion, can be constrained due to excess generation on the interface along with transactions across the interface. Real-time operating limits have been addressed using the appropriate NERC operating procedures. Additional fans were added to the McAdams autotransformer in July 2008 to increase its rating. Additional upgrades have been identified for the area's system improvements. These upgrades have a projected in-service date of 2011.

Some utilities are expecting to replace existing transmission line protection systems with more modern protection equipment. Other entities have reported that they have installed two statcom units at the Natchez 115 kV station to automatically support local area reactive power requirements. The statcom system is a fully integrated, inverter-based reactive compensation system. Statcom systems are cost-effective solutions that can provide tight voltage regulation and power factor correction to alleviate fluctuating voltage and VAr demands. This, combined with normal switched capacitor banks in the area, is a very economical alternative to SVCs and equally effective at solving common transmission grid problems such as voltage instability and voltage regulation. Utilities plan to continue to employ and research new technologies in order to improve and maintain bulk power system reliability.

Operational Issues

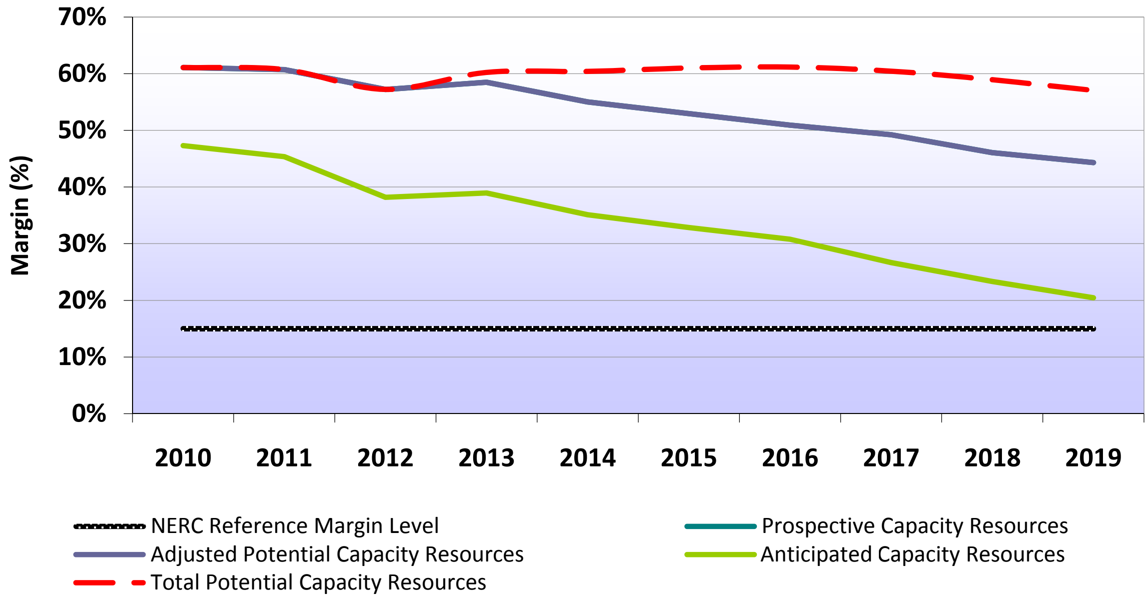
There are no existing or potential systemic outages that may impact reliability during the next 10 years. If peak demands are higher than expected, entities rely on reserve margins from individual company owned/operated power plants, and interconnections to SPP, Midwest ISO, and neighboring utilities from which wholesale energy can be accessed. If adequate resources cannot be procured from the short-term wholesale market, entities would rely on curtailing load, first to non-firm customers and then to firm customers.

No reliability concerns are anticipated for the ten-year period as a result of operational issues from the integration of variable resources or distributed resources. There are also no local environmental, regulatory restrictions, impacts due to high-levels of Demand Response or unusual operating conditions expected that might affect system reliability. Because EEAs (Energy Emergency Alerts) have been issued in the past for the Acadiana area, the SPP Independent Coordinator of Transmission - Entergy will continue to monitor this area closely and implement mitigation plans as necessary as part of its reliability coordinator function. A two-phase joint project to construct a 230 kV overlay in the Acadiana load pocket is currently in the construction phase with targeted in-service dates of 2011 and 2012.

Reliability Assessment Analysis

Projected net reserve margins for utilities in the subregion as reported between the years 2010 to 2019 are from 44.9 percent to 18.4 percent over the ten-year period (see Figure SERC-4). Capacity resources are expected to be adequate to meet demand for the period.

Figure SERC-4: Summer Peak Reserve Margin Projections



There is no subregional, Regional, state or provincial reserve margin requirement for this subregion. However, some individual entity criterions are established based on the balancing authority's most severe single contingency, load forecast and reserve requirement using historical allocations, and loss of load expectation studies (0.1 day/year).

Various utility resource planning departments in the subregion conduct annual studies (either in-house or through contractors) to assess resource adequacy. Modeling of resources and delivery aspects of the power system are used throughout the subregion in all phases of the studies. The overall goal of the studies is to ensure resources (existing and owned) are available at the time of system peak. Studies may take into account potential resource deactivations and anticipated unit outages. Results help develop one year and ten-year resource plans that meet target reserve margins. Some companies have reported that study results are approved by their internal board of directors.

It was reported that no significant changes from last year's studies were made to the current studies done for the period. Resources for the ten-year assessment are internal to the SERC Region and the Delta subregion. On average for the ten-year period, 36,393 MW of internal resources and 1,822 MW of capacity transactions which account for internal resources of non-reporting parties and for external resources were reported during this assessment period. These resources are considered to meet the NERC Reference Margin Level for the period.

Although some Delta subregion utilities participate in the SPP Reserve Sharing Group, the subregion is not dependent on outside resources to meet its demand requirements. Entities do not consider short-term (*i.e.* 1-5 years) and long-term (*i.e.* 6-10) reserve margin requirements differently.

Fuel supplies are anticipated to be adequate. Coal stockpiles are maintained at 45 days or more. Natural gas contracts are firm, with some plants having fuel oil back-up. Extreme weather conditions should not affect deliverability of natural gas. Typically, supplies are temporarily limited only when there are hurricanes in the Gulf of Mexico. There is access to local gas storage to offset typical gas curtailments. Many utilities maintain portfolios of firm-fuel resources to ensure adequate fuel supplies to generating facilities during projected peak demand. Those firm-fuel resources include nuclear and coal-fired generation that are relatively unaffected by winter weather events. Various portfolios contain fuel oil inventories located at the dual-fuel generating plants, approximately 10 Bcf of natural gas in storage at a company-owned natural gas storage facility, and short-term purchases of firm natural gas generally supplied from other gas storage facilities along with firm gas transportation contracts. This mix of resources provides diversity of the fuel supply chain and minimizes the likelihood and impact of potentially problematic issues affecting system reliability. Close relationships (contracts) are maintained with coalmines, gas pipelines, gas producers and railroads that serve coal power plants. These relationships have been beneficial to ensure adequate fuel supplies are on hand to meet load requirements. Upon the occurrence of fuel interruption or forced outage within some entity facilities, it is the procedure that exporting contracts out of the facility will be curtailed in coordination with the affected balancing authorities until operations can return to normal.

Energy-only, transmission-limited, variable resources or RPSs are not considered in resource adequacy assessments. Only firm capacity and firm transmission are considered in entity assessments. The majority of the utilities within the subregion have no Demand Response programs; however, those utilities that do have these programs report that they are treated as a load modifier in resource adequacy assessments. The effects of Demand Response are incorporated into the load forecast which is treated stochastically. Transmission planners continue to study variable generation integration (like wind), and its impact on reliable transmission operations. System operations and power marketing use the wind forecasting services to manage the variable output of the wind farms.

In addition, entities do not anticipate any unit retirements that could affect reliability during the assessment period.

Various companies throughout the subregion perform individual studies to assess transient dynamics, voltage and small-signal stability issues for summer peak conditions in the near-term planning horizons as required by NERC Reliability Standards. For certain areas of the subregion, the 2010 summer assessment from the study was chosen as a proxy for the near-term evaluation. No critical impacts to the bulk power system were identified. While there are no common subregion-wide criteria to address transient dynamics, voltage and small-signal stability issues, some utilities have noted that they adhere to voltage schedules and voltage stability margins. In addition, some utilities employ static VAr compensation devices to provide reactive power support and voltage stability. UVLS programs are also used to maintain voltage stability and protect against bulk power system cascading events. An existing

280 MW UVLS scheme is used in the western area of Texas. No additional UVLS schemes are currently planned for the subregion.

While Delta subregion companies do not employ a minimum dynamic reactive requirement or margin, it does employ the following. P-V curves are commonly used to determine the system's critical operating voltage and collapse margin by analyzing the relationship between bus voltage and total active power supplied to loads (MW)[117].The voltage stability criterion used by the Delta subregion companies is a voltage stability margin of five percent from the nose point (voltage collapse point) load on the P-V curve. Stability studies performed incorporated P-V curve analyses to ensure that this criterion is met on the system. If necessary, stability limits can be imposed on transmission elements in order to meet this criterion.

Under transient conditions, the companies employ the following voltage dip criteria:

(i) For the loss of a single transmission or generation component, with or without fault conditions, the voltage dip must not exceed 20 percent for more than 20 cycles at any bus; must not exceed 25 percent at any load bus; and must not exceed 30 percent at any non-load bus; and

(ii) For the loss of 2 or more transmission or generation components under three-phase normal-clearing fault conditions, or the loss of 1 or more components under single-phase delayed-clearing fault conditions, the voltage dip must not exceed 20 percent for more than 40 cycles at any bus; and must not exceed 30 percent at any bus.

The Delta subregion has identified a dynamic and static reactive power-limited area on the bulk power system. The western area of Texas is defined as a load pocket, which is an area of the system that must be served at least in part by local generation. This load pocket requires importing of power across the bulk power system in order to meet the real power demand. The reactive power requirements of this load pocket are supplemented by the use of capacitor banks, as well as a static VAr compensator. Several projects, involving both bulk transmission upgrades/additions and generation resource additions, are currently under evaluation in order to increase the real and reactive demand-serving capability of the western area.

The bulk transmission projects will be phased-in incrementally to maintain the integrity of the system according to NERC Reliability Standards. No SPSs or RASs[118] have been planned in lieu of the transmission projects.

Resource and transmission planning along with study contingency events help entities to prepare for catastrophic events. Maintaining adequate reserves is also thought to help mitigate the effects of a single event. Close relationships with neighboring utilities and routine emergency operating drills are

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[117] Voltage Stability Analysis of GRIDS Connected Wind Generators. http://eeeic.eu/proc/papers/11.pdf

[118] RAS (Remedial Action Scheme) is another name for a Special Protection System. http://www.nerc.com/files/Glossary_12Feb08.pdf

important practices of utilities as well. Entities within this subregion are routinely exposed to hurricanes. Detailed emergency response plans are developed for dealing with the consequences of hurricane damage to electric systems. To mitigate these events, gas-fired power plants do not rely on a single pipeline for transportation of natural gas. Likewise, most entities do not heavily rely on imports outside the subregions due to the loss of a major import that could negatively affect reliability.

Some utilities are expecting to replace existing transmission line protection systems with more modern protection equipment. As noted earlier, other entities reported that they have installed two statcom units at the Natchez 115 kV station to automatically support local area reactive power requirements.

Utilities plan to continue to employ and research new technologies in order to improve and maintain bulk power system reliability. The evaluation and development of new smart grid programs such as AMI (Advanced Metering Infrastructure) and PMU (phasor measurement unit) within certain utilities are currently moving forward to determine the reliability benefits that may be obtained with the newer technology and real-time data acquired through the use of the technology.

Certain utilities plan to deploy additional PMUs, doubling their current deployment. These units are expected to provide more complete real-time information of the voltage and stability of the bulk power system, to enhance the accuracy of the existing models, and to provide early warning of voltage or stability problems. They have not yet decided to deploy smart meters or other smart grid technologies, but are actively investigating the benefits of the technologies in the long run. The technologies contemplated include smart meters, web portals, in-home displays, and automated distribution equipment for better voltage control. It is expected that benefits will be derived from these technologies, including faster outage reporting, faster outage response, and more complete restoration confirmation. These reliability benefits are largely anticipated for the distribution systems, and not on the bulk power delivery system. Cyber security of smart meters is a concern; however, standards are being developed to address cyber security for smart grid technologies.

Project reductions, deferrals, or cancellations are not expected for the time period. To minimize reliability concerns for the 2010-2019 timeframe, entities are studying reliability with a critical and conservative approach. Any issues that result from these studies are addressed within the appropriate timeframe. Curtailment processes and emergency response plans are routinely updated for improvement. As necessary, transmission-wide and local area procedures, re-dispatch and operating guidelines will be implemented to maintain reliability for the 2010 summer and later years. Overall, there are no other anticipated reliability concerns for the assessment period.

SUBREGION DESCRIPTION

The Delta subregion covers portions of Louisiana, Arkansas, Missouri, northeastern Oklahoma, western Mississippi, southeastern Texas, and three counties of southeastern Iowa.

GATEWAY SUBREGION

DEMAND

The 2010 summer aggregate Total Internal Demand forecast for the utilities in the Gateway subregion is 19,113 MW and the forecast for 2019 is 20,032 MW. This year's forecast CAGR for 2010 to 2019 is 0.63 percent which is lower than last year's 2009 to 2018 CAGR of 0.91 percent. Differences in the forecast growth rate are attributed to adjustments made to assumptions in price increases over the long-term due to the expectation of carbon price implementation during the time period. Growth rates also take into account the adjustments of new demand forecast in 2010 that are already captured in this year's forecast, the effects of a slow economy and energy conservation activities throughout the subregion.

The Gateway subregion's peak demand is reported on a non-coincident basis and reserves are evaluated for summer peak conditions. Recent forecast assumptions are based on normal temperatures, decreased economic growth, and reductions in projected sales to the residential sector. Some entities use economic assumptions from Economy.com for the development of their load forecast information. Current forecasts call for a 0.8 percent growth in GDP for the St. Louis area in 2010.

Gateway utilities have experienced increased levels of participation in energy conservation and efficiency programs since 2009. Utilities continue to work with customers to save energy in order to minimize generation production impacts to the environment and to reduce costs. Energy efficiency programs are numerous and active throughout the subregion. Gateway entities promote a variety of programs at the residential level including Energy Star appliance rebate/loan programs, inefficient water heater, refrigerator, and air conditioner replacement programs, online energy audits, and low-income weatherization programs. Gateway entities also work with commercial and industrial customers to promote energy-efficient commercial buildings through building operator certification programs, lighting incentive programs, and infrared thermography and thermal energy leak-detection programs. Some Gateway utilities sponsor educational energy workshops, and work with customers to investigate solar energy applications. Energy efficiency information is posted on some utility web sites to inform and educate consumers to help manage rising energy costs and to promote in-state economic development while protecting the environment. Independent third-party contractors have been retained by some utilities to perform all evaluation, measurement, and verification for the programs after they have been rolled out. Results are being reviewed to evaluate the cost and energy savings of these programs. Web statistics, customer surveys and recent research help other utilities measure the effectiveness of new and existing programs. Increased outreach by some of the smaller entities has doubled the participation of some customers in the efficiency rebate programs and tripled the participation in the loan programs.

Demand Response programs within the subregion are small and varied and include residential, commercial, and industrial programs. Load management programs can reduce peak electric demand during high summer temperatures when the cost of electricity is at its highest. Some programs reduce peak electric demand for large commercial and industrial customers. When customers are called on to participate, the load reduction can create savings for all parties involved in the program. Other programs such as Residential and Small Commercial Smart Thermostat Programs (direct load control through smart thermostats) and voluntary price responsive programs are in place to curtail air conditioning load and help reduce demand. Some entities have contracted with third parties to evaluate the costs, energy savings, and overall effectiveness of these programs. These evaluations are generally conducted annually and include a comprehensive report at the end of a program cycle. Under Illinois state RPS guidelines, DSM resources are not allowed to satisfy Renewable Portfolio Standards.

Entities that participate in the Midwest ISO market follow the Midwest ISO's new requirements regarding assessing peak demand forecast under its Module E tariff.[119] Per this tariff, entities evaluate the standard error of the forecast, which reflects the statistical uncertainty around the forecast, as well as the elasticity of the peak demand with respect to weather. The forecast explicitly addresses extreme summer conditions only by consideration of high temperatures experienced on average over the period used to calculate normal weather. The weather elasticity is developed with consideration of only the highest few points of the forecast, and therefore is applicable specifically to temperatures in the top of the forecast summer temperature range. However, extreme temperatures beyond the normal annual high temperature are not explicitly considered beyond the application of the weather elasticity parameter. To develop these forecasts, some utilities use regression models, multiple forecast scenario models, and econometric models. Economic assumptions, alternative fuel pricing, electric pricing and historical temperature and weather (pessimistic and optimistic conditions) pattern information are considered individually by each subregion utility.

GENERATION

Companies within the Gateway subregion expect to have the following capacity on peak. Capacity in the categories of Existing (Certain, Other and Inoperable), Future (Planned and Other) and Conceptual are projected to help meet demand during this time period. Variable capacity is determined from the Midwest ISO practice of allowing a maximum of 8[120] percent of wind nameplate capability as a capacity resource. Planned additions of significance include 1,650 MW of Prairie State generation (825 MW in 2011 and 825 MW in 2012).

[119] The Midwest ISO Business Practice Manual: BPM 011 – Module E – Resource Adequacy documents at http://www.midwestiso.org/page/Regulatory+and+Economic+Standards

[120] Capacity of wind generation in the Midwest ISO Region is limited to 8 percent of nameplate capability based on Midwest ISO Business Practice Manual for Resource Adequacy (BPM-011-r5)

Table SERC-5: Gateway Capacity Breakdown		
Capacity Type	**2010 (MW)**	**2019 (MW)**
Existing-Certain	24, 352	24, 366
Nuclear	2,255	2,255
Hydro/Pumped Storage	824	824
Coal	14,062	14,062
Oil/Gas/Dual Fuel	6,930	6,930
Other/Unknown	273	287
Solar	0	0
Biomass	0	0
Wind	8	8
Existing-Other	92	92
Existing-Inoperable	26	26
Future-Planned	12	1,718
Future-Other	0	0
Conceptual	0	599
Wind	0	59,910
Solar	0	0
Hydro	0	0
Biomass	0	0

The generation resources to serve the retail loads for the period are predominantly located within the Gateway subregion or in the Midwest ISO balancing area. Some utilities have filed integrated resource plans with their local commissions. As most Gateway entities are members of the Midwest ISO, they adhere to the planning reserve margin requirements established by the Midwest ISO Loss of Load Expectation Working Groups (LOLE). These same entities also apply the planning reserve requirements developed in the Midwest ISO Module E process, which help to determine more consistent demand requirements across the Midwest ISO footprint. Generation interconnection requests are overwhelmingly from wind plant developers, as over 5,000 MW of wind capacity are proposed to connect within the subregion. The capacity available from such plants would follow the Midwest ISO Business Practice Manual for Resource Adequacy, and is assumed limited to 8 percent of nameplate capability for 2010-2011. No solar or biomass projects are under study for connection to the transmission system in the subregion. However, connections of smaller plant developments to the sub transmission or distribution systems in the Gateway subregion are being studied, including approximately 30 MW of waste heat, 10 MW of solar, 33 MW of landfill gas, 240 MW of wind, and 5 MW of hydro generation.

Capacity Transactions on Peak

The Gateway subregion reported the following imports and exports for the ten-year assessment period. These firm imports and exports have been accounted for in the reserve margin calculations for the subregion. All capacity purchases and sales are on firm transmission within the Midwest ISO footprint and direct ties with neighbors. Day-to-day capacity and energy transactions are managed by the Midwest ISO with security-constrained economic dispatch and LMP. Overall, the subregion is not dependent on outside imports or transfers to meet the demands of its load.

Table SERC-6: Gateway Purchases and Sales

Transaction Type	2010 Summer (MW)	2014 Summer (MW)	2019 Summer (MW)
Firm imports (external subregion)	2,780	596	596
Firm exports (external subregion)	4,686	780	741
Expected imports (external subregion)	0	0	0
Expected exports (external subregion)	0	0	0
Provisional imports (external subregion)	0	0	0
Provisional exports (external subregion)	0	0	0

Transmission

Transmission system upgrades on the Gateway 138 kV and 161 kV transmission system should dominate the construction activities over the next few years. These projects involve replacement of conductors, providing increased clearances to ground, and replacement of limiting terminal equipment. Each planned project is reported to be on schedule and is not anticipated to be delayed. The Baldwin-Rush island 345 kV line is scheduled for completion in the fall of 2010, ahead of the Prairie State generation additions scheduled for 2011 and 2012.

Several 345 kV projects have been planned or are in the final planning stages to reinforce the transmission supply to local load pockets in the Ameren footprint. Public workshops have been held to inform and educate the public regarding the needs for the transmission reinforcements and the possible line routes that could be used to complete these projects; more workshops are planned. Certificates of Convenience and Necessity are being pursued by the Ameren-Illinois utilities. Additional transmission projects are in the Conceptual planning phase, including major 345 kV transmission line extensions to increase transfer capability, to connect wind resources and enhance the deliverability of these resources throughout the Gateway subregion. A number of these major transmission system projects are expected to be placed in service over the next 10 years. Other transmission system expansions are being contemplated, but the timing for such additions awaits a definitive need. Studies are being conducted through the Midwest ISO investigating a 765 kV overlay through the Gateway subregion to connect and deliver wind resources within the Midwest ISO footprint. Some of the 345 kV projects listed would also be required to provide a more efficient delivery system for a 765 kV development in the subregion. To enhance the lead-time for some of these projects in Illinois, legislation is being pursued to expedite the approval process with the Illinois Commerce Commission.

The 2010 summer seasonal assessment performed by the NTSG indicates favorable import capabilities from multiple entities. No constraints within the subregion have been identified that could significantly impact reliability during the upcoming summer assessment period.

Continued use of the phasor measurement equipment installed at Ameren's Callaway, Rush Island, and Newton Plants is expected to help in providing post-disturbance data. Additional phasor measurement equipment will be installed in the next few years at other large plants and major substations on the Ameren system to enhance data collection and provide additional post-contingency information on system disturbances. With time, these installations, in combination with other such phasor measuring equipment installed elsewhere on the interconnected system, will provide another tool to operations personnel in assessing immediate near-term conditions on the interconnected system. Some members have upgraded distance relays[121] at specific substations and switchyards to decrease outage time to their local customers. Distance relays provide better sectionalizing and quicker response time to transmission lines located in very rural areas. These relay additions do not directly improve bulk power system reliability, but they do improve the reliability of the local power delivery system. Overall, no significant new technologies, systems or transmission equipment have been added to the system since the last assessment period.

Operational Issues

Entities within the Gateway subregion are not anticipating any existing or potential systematic outages during the next 10 years. However, some generator operators note that nuclear refueling outages are scheduled on average every 18-24 months during off-peak conditions and are typically three weeks in duration. These outages are necessary, and affect the availability of capacity during that time period, but should not pose any reliability issues during the lighter load periods provided that the outages are coordinated with the outage of other generation resources in the market.

[121] A distance relay is a protective relay designed to protect high voltage transmission systems from faults up to a certain distance (using impedance, voltage and current comparisons) away from a substation but not beyond that point.

To address operational measures during higher peak demands, some entities use contracts for additional capacity, access Demand Response programs or operate generating resources at emergency load levels.

Several entities report that there are environmental regulations that limit the number of hours of operation, tons of emissions, and thermal discharges of some power plants. However, these entities monitor plant and unit operations to ensure that the regulatory limits do not constrain operations during summer peak conditions. Although some peaking plants have *de minimus* air permits that limit the number of hours of operation to approximately 950 hours per year, these limitations should not prevent these units from operating when needed for reliability. The impact of hazardous air pollutant (HAP) regulatory restrictions is currently being studied. Entities are presently managing these restrictions and do not expect the restrictions to be detrimental to system reliability in the near future.

Utilities are recognizing that voltage regulation on distribution systems with distributed generation is becoming a concern. However, entities within the subregion have very few distributed and Demand Response resources connected to the systems. The availability of large amounts of low-cost base-load generation during off-peak load conditions can result in congestion and real-time transmission loading issues. The addition of wind generation in the Gateway subregion and surrounding balancing areas to the north and west may exacerbate the transmission loading concerns in some areas. Midwest ISO members are studying the impacts of integrating large amounts of variable generating resources on the system. This issue of wind integration has been elevated to a higher level within the Midwest ISO as the amount of wind generation is expected to increase dramatically over the next several years. Generation re-dispatch may be required at some plants to maintain transmission loadings within ratings, subject to the security-constrained economic dispatch algorithm of the Midwest ISO. Curtailment of some transactions may also be required. Some base-load generation may be forced off during minimum load conditions because too much generation would be available to serve the load. Presently, these are market issues and not reliability concerns.

Reliability Assessment Analysis

Projected net reserve margins for utilities as reported between the years 2010 and 2019 are from 2 34.8 percent to 18.2 percent over the ten-year period (see Figure SERC-5). There are no Regional, subregional, or state reserve margin requirements for the entities in the subregion. Gateway subregion utilities have traditionally tried to maintain a planning reserve margin of at least 15 percent. As all Gateway load-serving entities are members of the Midwest ISO, they follow the planning reserve requirements of the Midwest ISO. For 2010, the planning reserve margin requirement is 11.94 percent based on a Loss-of-Load-Expectation metric of 1 day in 10 years, as identified in the Midwest ISO Resource Adequacy Business Practice Manual[122]. Entities that participate in the Midwest ISO market generally have excess capacity, and use the LOLE reserve margins as a guideline for planning. A slight planning reserve margin surplus has occurred since last summer due to the economy and reductions in load.

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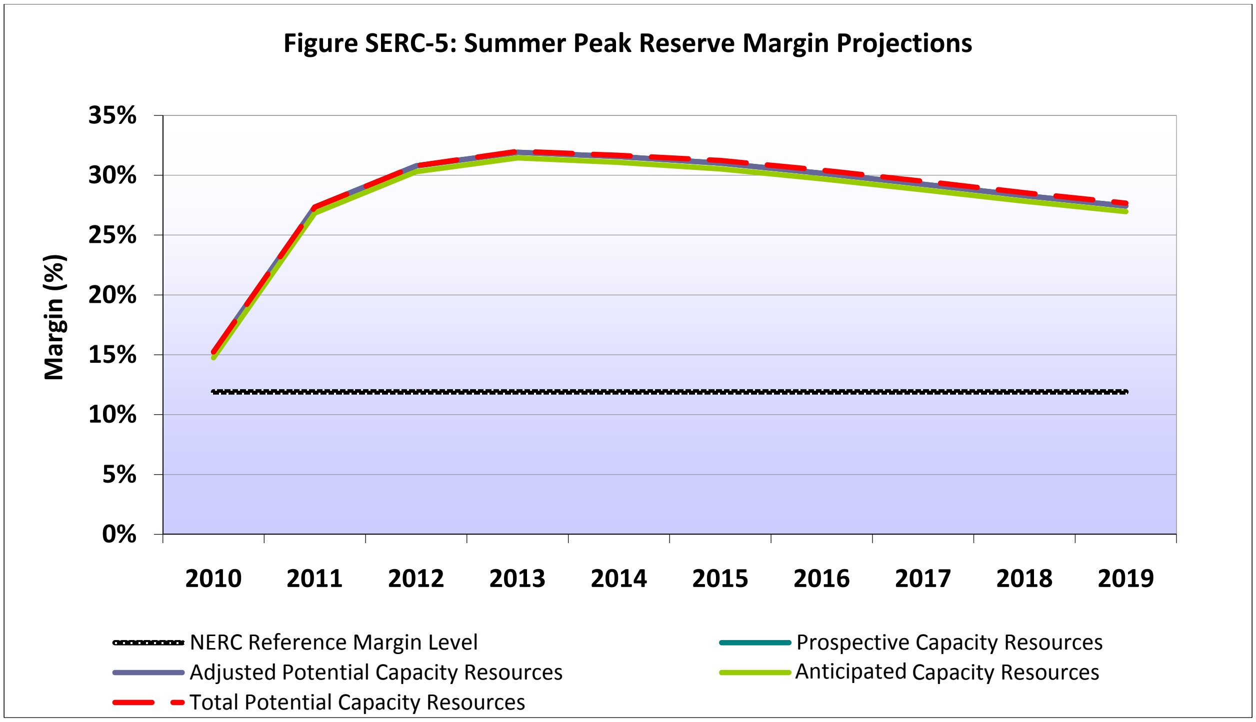
[122] Midwest ISO Resource Adequacy Business Practice Manual; http://www.nerc.com/docs/pc/ris/MISO_Resource_Adequacy_TP-BPM-003-r3.pdf



The Midwest ISO resource adequacy and operational procedures can be found in the Midwest ISO Resource Adequacy Business Practice Manual (BPM). A 50/50 load uncertainty was used in their latest LOLE analysis. A 90/10 load forecast was not required; however, if it were performed, it is not projected to increase the reserve requirements significantly due to the geographical size and load diversity within the Midwest ISO. The use of a 90/10 forecast would increase demand by about 5 percent above the 50/50 forecast level for the Gateway subregion.

Assuming an 11.94 percent planning reserve margin for a 50/50 load level, the reserve margin for a 90/10 load level would be about 6.6 percent. A small amount of interruptible load may be available for curtailment, along with voltage reduction to reduce the system load. Appeals for voluntary load conservation from the Midwest ISO and Gateway utilities would also be available if needed to cover capacity shortages. Based on experience, resources are expected to be adequate for the assessment period.

On average for the ten-year period, 23,037 MW of internal resources and 879 MW of capacity transactions, which account for internal resources of non-reporting parties and for external resources were reported during this assessment period. Assuming an 11.94 percent planning reserve margin from the Midwest ISO, these resources are believe to be adequate to meet the needs of the subregion for the period.

Some entities are following the preliminary guidance of the Midwest Planning Reserve Sharing Group (MPRSG) considering a long-term planning reserve margin of 17 percent. Other entities within the subregion have reported that they are not treating long-term and short-term margins differently.

Most load-serving entities within this subregion are members of the Midwest ISO Contingency Reserve Sharing Group. The Midwest ISO presently does not require its load-serving entities to obtain generation reserve commitments beyond one planning year, but Midwest ISO and its members are in the process of developing a long-term planning reserve margin program.

Fuel supply in the area is not projected to be a problem in the case of a temporary interruption. Policies considering fuel diversity and delivery are in place throughout the subregion to ensure that reliability is not impacted. Several entities have policies that take into account contracts with surrounding facilities and suppliers, alternative transportation routes, and alternative fuels. These fuel procurement practices help to ensure balance and flexibility to serve anticipated generation needs. To help coordinate fuel supply issues in the market, entities who are members of Midwest ISO enter derate or outage resource conditions into the Midwest ISO Outage Scheduler as required by the Midwest ISO balancing authority for the operational planning horizon. In the event that significant generator outages occur, entities may also rely on market purchases to meet demand.

It is not common for entities within the subregion to own, purchase, or rely on any energy-only or transmission-limited resources to meet resource adequacy requirements. Those that consider these resources follow the guidelines of the Midwest ISO Resource Adequacy BPM. The manual establishes guidelines for any resource to qualify as a planning reserve credit that can be used to meet resource adequacy requirements.

Presently, renewable portfolio standards or other mandates do not affect resource planning in the Gateway subregion. Entities do not rely upon variable resources to meet resource adequacy requirements. However, some entities have strategic plans to investigate renewable resource projects and contracts. Because of this process, one entity recently executed a long-term (20 year) contract for 70 MW of output from a new wind farm in Illinois. This resource has been added to the entity's diverse portfolio of capacity and energy resources for the assessment period.

To ensure reliable integration and operation of variable resources, some entities depend on studies that are supplied from the Midwest ISO, as well as from their own resource planners. The Midwest ISO BPM also defines how Demand Response is to be measured and verified. Demand Response presently does not have a significant impact on resource adequacy; however, new initiatives are being evaluated. Subregion entities have a diverse portfolio of capacity and energy resources to ensure that demand can be met for the assessment period.

A few generating units have been retired within the subregion since last summer. In the fall of 2009, the Meredosia units #1 and #2 (120 MW total) were removed from operation and the Lakeside coal-fired plant was retired (76 MW). The Lakeside capacity was replaced with the 208 MW coal-fired Dallman 4 unit. The Midwest ISO's Attachment Y[123] procedures approved the retirement of all of these units from the market after a comprehensive study and review to ensure that reliability was not impacted. Other

[123] Midwest ISO's Transmission and Energy Markets Tariff Attachment Y is included in their Transmission Planning Business Practice Manual (BPM-20) in Section 7.2 electronically located at: http://www.midwestmarket.org/publish/Folder/3e2d0_106c60936d4_-76850a48324a

potential retirement options will be studied in 2011 IRP studies and through other Midwest ISO Attachment Y requests.

No UVLS programs are expected to be installed within the assessment period.

No long-term special protection systems are planned to be installed to mitigate single contingency transmission system deficiencies assuming that transmission facilities can be built. Special protection/remedial action systems may need to be installed for multiple contingency events or as temporary measures until transmission facilities can be constructed and placed in service.

Planning processes to address catastrophic events are commonly used within the subregion. One example of these processes is maintaining a sufficient coal inventory to handle a coal disruption. Another example of catastrophic planning around the subregion would be gas-fired generation being supplied by multiple pipelines, thus the disruptions of a single pipeline would not have a significant impact. Gateway utilities also have a large number of interconnections and are members of Midwest ISO, thus a problem with a single import path is not expected to impact reliability. Contingency analyses to meet the NERC TPL standards and local planning criteria are performed annually by the larger members in the subregion. Extreme disturbance studies and incremental transfer capability studies are also performed by Gateway utilities. A robust transmission system with a diverse portfolio of capacity resources, including company-owned generation, member/municipal-owned generation, and contractual agreements, are also part of the planning process to ensure a reliable system for the Gateway subregion members.

For the 2009 annual assessment of the Ameren transmission system, peak load conditions for 2010 summer and 2014 summer were used as the basis for conducting studies of normal, single contingency, and multiple contingency conditions. Models of 2010 light load conditions with heavy exports, 2010 fall conditions with heavy exports, and 2014 summer shoulder conditions with heavy exports were also used for the near-term assessment to cover expected critical system conditions. Expected 2019 summer conditions were also reviewed. No cascading outages[124] are expected to occur, even for extreme contingency conditions, assuming the completion of planned transmission projects. As a result of these annual assessment studies, corrective action plans consisting of planned and proposed upgrades for the Ameren transmission system have been developed. Results of the 2009 assessment have been used to update and revise these corrective action plans, which include projects to relieve thermal, voltage, and local stability concerns. Gateway utilities also work with the SERC NTSG and LTSG in performing transmission assessment studies to comply with NERC TPL Standards. Some entities also participate with the ERAG[125] sponsored the MSRSWS (MRO-RFC-SERC West-SPP) group to address some of the inter-Regional transfer capability study needs of the SERC Region.

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[124] 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. http://www.nerc.com/files/Glossary_12Feb08.pdf

[125] Eastern Interconnection Reliability Assessment Group; http://www.erag.info/

To address transient stability modeling issues, some Gateway utilities conduct transient stability studies using winter or off-peak load levels. This is considered to be a more conservative approach than using summer-peak load levels. Most entities within the subregion participate in the SERC DSG to assess annual dynamic conditions on the system. The larger entities within the subregion use the models developed by the ERAG and DSG to perform their own transient stability studies. During 2009, a number of Category C transient stability simulations were performed for several selected plants and substations connected to the Ameren transmission system considering expected 2009 light load, 2010 summer peak load, and 2014/15 winter peak load conditions. A number of Category D transient stability simulations were also performed for several selected plants and substations connected to the Ameren transmission system considering expected 2009 light demand, 2009/10 winter peak demand, 2010 summer peak demand, and 2013/14 winter peak demand conditions. No Gateway subregional level criteria have been set for voltage or dynamic reactive requirements. Some utilities consider a steady state voltage drop greater than five percent (pre-contingency-post contingency) as a trigger to determine if further investigation is needed to ensure there are no widespread outages. Voltage stability assessments have been performed for some load centers in Illinois. Some of these areas are subject to voltage collapse for specific double-circuit tower outages during peak conditions, but widespread outages are not expected. Plans to build new transmission lines to mitigate the contingencies are proceeding. Public involvement has been solicited to develop possible line routes. Applications to the Illinois Commerce Commission for Certificates of Convenience and Necessity have been filed or are expected to be filed in 2010 to build these new lines by summer of 2015. Overall, individual or SERC group studies have not reported any other major issues or concerns within this subregion.

Other than the phasor measuring equipment discussed earlier, no significant new technologies, systems or transmission equipment have been added to the system since last year, or are planned for the assessment period. Entities are in the process of researching the implementation of smart grid technology within the area, but there are no reports of the new technology being installed on the system for the period.

Gateway entities have not experienced any project delays, etc. which would impact reliability in the SERC Region. In order to minimize impacts on the system that cause reliability concerns, entities plan for the system to have adequate capacity to meet the load and planned (annual) maintenance outages to keep generating resources reliable. The transmission system is monitored continuously and facilities are planned and constructed to maintain or enhance reliability, as needed. Overall, utilities do not expect any significant reliability concerns for 2010 summer and the next 10 years.

Subregion Description

The Gateway subregion covers the southern two-thirds of Illinois and much of eastern Missouri, and includes a small load pocket in northwestern Missouri. The St. Louis metropolitan area is the largest load center in the subregion.

SOUTHEASTERN SUBREGION

DEMAND

The 2010 summer aggregate Total Internal Demand forecast for the utilities in the Southeastern subregion is 48,472 MW and the forecast for 2019 is 58,046 MW. This year's forecast CAGR for 2010 to 2019 is 1.96 percent. Growth rates are predicted to be less than last year's rate of 2.22 percent. The slowdown in housing expansion, lower peaks due to slower consumer growth, the size and timing of several projected new large industrial loads and other general economic factors are the reason for the lowered growth rate. Peak demand forecast is based on normal weather conditions and uses normal weather, normal load growth and conservative economic scenarios.

Demand Response programs within the subregion consist of programs ranging from real-time pricing/critical peak pricing (reduce energy usage based on price signaling), interruptible demand programs (requests customers to reduce energy usage) to direct load control programs (energy provider reduces customer energy usage). Entities within the subregion have the ability to control various amounts of load when needed for reliability purposes.

One example of a Demand Response program is the H2O Plus program, which uses the storage capacity of electric water heaters. This program allows entities to install load control devices that can be activated during peak demand periods, which promotes the following benefits:

- Help reduce the need to build or purchase capacity
- Respond to volatile wholesale energy markets
- Improve the efficiency (load factor) as well as the use of generation, transmission, and distribution systems
- Provide low-cost energy to member cooperatives
- Increase off-peak kWh sales

Other programs in place allow entities to interrupt air conditioning systems during periods of peak demand, reduce line losses, regulate voltage drops across the circuit, and reduce the voltage on the distribution circuits at the voltage regulator/load tap transformer that results in customer demand reduction (Distribution Efficiency Program, Conservation Voltage Reduction).

Various utilities have residential Energy Efficiency programs that may include educational presentations, home energy audits, compact fluorescent light bulbs, electric water heater incentives, heat pump incentives, energy efficient new-home programs, Energy Star appliance promotions, loans or financing options, weatherization, programmable thermostats, and ceiling insulation. Commercial programs may include energy audits, lighting programs, and plan review services.

Other programs such as business assistance/audits, weatherization assistance for low-income customers, residential energy audits and comfort advantage energy-efficient home programs promote reduced energy use, supply information and develop Energy Efficiency presentations for various customers and organizations. Utilities are also beginning to work with state's energy divisions on Energy Efficiency planning efforts. Training seminars addressing Energy Efficiency, HVAC sizing, and energy-related end-use technologies are also offered to educate customers.

To address measurement and verification of Energy Efficiency and DSM programs, entities may use third parties to conduct impact/process evaluations for commercial programs, or use Demand Response statistical models to identify the difference between the actual consumption and the projected consumption absent the curtailment event. Response may also be tracked and verified by the readings of meters, as well as testing residential and commercial summer load-control programs for verification of demand reduction through generation dispatch personnel. Evaluations may be conducted annually with a comprehensive report due at the end of a program cycle. Reports are expected to determine annual energy savings and portfolio cost-effectiveness.

To assess variability within the demand forecast, some entities develop demand forecasts using econometric analysis based on approximately 40-year (normal, extreme and mild) weather, economics and demographics. Others within the subregion use the analysis of historical peaks, reserve margins and demand models to predict variance.

Generation

Utilities in the Southeastern subregion expect to have the following capacity on-peak. Capacity in the categories of Existing (Certain, Other and Inoperable), Future (Planned and Other) and Conceptual is projected to help meet demand during this time period. Variable capacity is limited within this subregion and is not commonly included in calculations.

Table SERC-7: Southeastern Capacity Breakdown		
Capacity Type	**2010 (MW)**	**2019 (MW)**
Existing-Certain	59,988	59,127
Nuclear	5,772	5,820
Hydro/Pumped Storage	5,041	5,091
Coal	25,373	24,715
Oil/Gas/Dual Fuel	23,773	23,471
Other/Unknown	13	13
Solar	0	0
Biomass	17	17
Wind	0	0
Existing-Other	3,291	3,370
Existing-Inoperable	0	0
Future-Planned	822	8,653
Future-Other	0	0
Conceptual	0	2,932
Wind	0	0
Solar	0	0
Hydro	0	0
Biomass	0	0

For Future and Conceptual capacity resources, entities go through various generation expansion study processes to determine the quantity and type of resources to add to the system in the future. Utilities have reported that generation reliability analyses are conducted typically for the peak period four years ahead. With the same or greater lead-time, some companies engage processes for self-building or soliciting from the market any needed capacity resources. Load forecasts are reviewed yearly and resource mix analyses are performed to determine the amounts and types of capacity resources required to meet the companies' obligations to serve. By the time the reliability analysis is conducted, those capacity resources have been committed by the companies and have high probability of regulatory approval. Power purchase agreements are also contracted from the market by that time. The resulting inputs to the reliability analyses are known or have very high confidence.

While entities within this subregion do not apply a confidence factor to the Conceptual resources, some entities have reported that recent history suggests that a 20 percent confidence factor may be reasonable to apply to these types of resources. Conceptual resources may be based on projected needs of the customers served. Reliability, environmental, and economic issues are also considered. Other companies review their interconnection service queues to identify potential future resources to be interconnected to their transmission system. If there are no confirmed transmission service requests or native load reservations identifying these facilities as the source, then these facilities are subsequently categorized as Conceptual.

Capacity Transactions on Peak

Southeastern utilities reported the following imports and exports for the ten-year reporting period. The majority of these imports/exports are backed by firm contracts for both generation and transmission; however, none have been reported to be based on partial path reservations. These firm imports and exports have been included in the reserve margin calculations for the subregion. Overall, the subregion is not dependent on outside imports or transfers to meet the demands of its load.

Table SERC-8: Southeastern Purchases and Sales

Transaction Type	2010 Summer (MW)	2014 Summer (MW)	2019 Summer (MW)
Firm imports (external subregion)	6,467	7,847	6,785
Firm exports (external subregion)	6,304	6,556	4,423
Expected imports (external subregion)	0	0	0
Expected exports (external subregion)	0	0	0
Provisional imports (external subregion)	0	0	0
Provisional exports (external subregion)	0	0	0

Transmission

Current economic conditions have resulted in lower load forecasts, which may delay the need for certain projects. Re-evaluated need dates may push projects out in time, but this is not a reliability issue.

No reliability impacts are foreseen due to target in-service dates of transmission upgrades as identified in Table 3 as not being met. The economic environment is resulting in reduced demand forecasts which in turn tend to delay the needs for some of these transmission improvements.

The utilities in the subregion have not identified any anticipated unusual transmission constraints that could significantly impact reliability. Additionally, there were no significant technologies that were added in the past year to improve bulk power system reliability. However, GTC (Georgia Transmission Corporation) and Southern Company developed a new 500 kV transmission tower design (Delta) for GTC's Thomson – Warthen 500 kV line project, which was completed in November of 2009. The new design could potentially affect reliability in a positive way in that it is more easily maintained and, in the event of an unplanned outage, it can enable restoration of a 500 kV line quicker than the steel lattice type structure. The new design is now the standard for new 500 kV lines for GTC and Southern Company. Entities continue to investigate the use of these new technologies to determine if they are economically viable to deploy on the system.

Operational Issues

Currently, there are no known existing or potential systemic outages that may impact reliability during the next 10 years. Several of the proposed climate legislations or anticipated EPA regulation could lead to potential unit retirements in the planning horizon. Utilities continue to evaluate reliability impacts of these potential retirements, and solutions are being developed to address them. As such, these impacts are not foreseen as a reliability concern. However, if the legislation or regulation requires unavailability of significant amounts of existing generation across the Region, then the ability to procure and/or construct replacement generation within a given timeframe could present a reliability concern.

If peak demands are higher than forecast, entities use existing reserves and purchase additional capacity from the market, if needed, to meet system requirements. Utilities also follow various emergency procedures related to EOP-002[126] that allow cancellation of non-firm sales, dispatch generation to emergency ratings, implementation of DSM programs and contacting the reliability coordinator for emergency capacity/energy (and various other steps). The last step in the process is to shed firm load. Balancing authority operators are routinely trained and conduct simulations regarding capacity shortfalls and implementation of mitigation procedures.

Fossil generating units in the Southern control area have operating limits related to air and/or water quality. These are derived from both federal and state regulations. A number of these units have unique limits on operations and/or emissions; some are annual limits while others are seasonal. These restrictions are continually managed in the daily operation of the system while maintaining reliability. Overall, no existing conditions are expected to impact the reliability on the bulk power system as a result of environment restrictions.

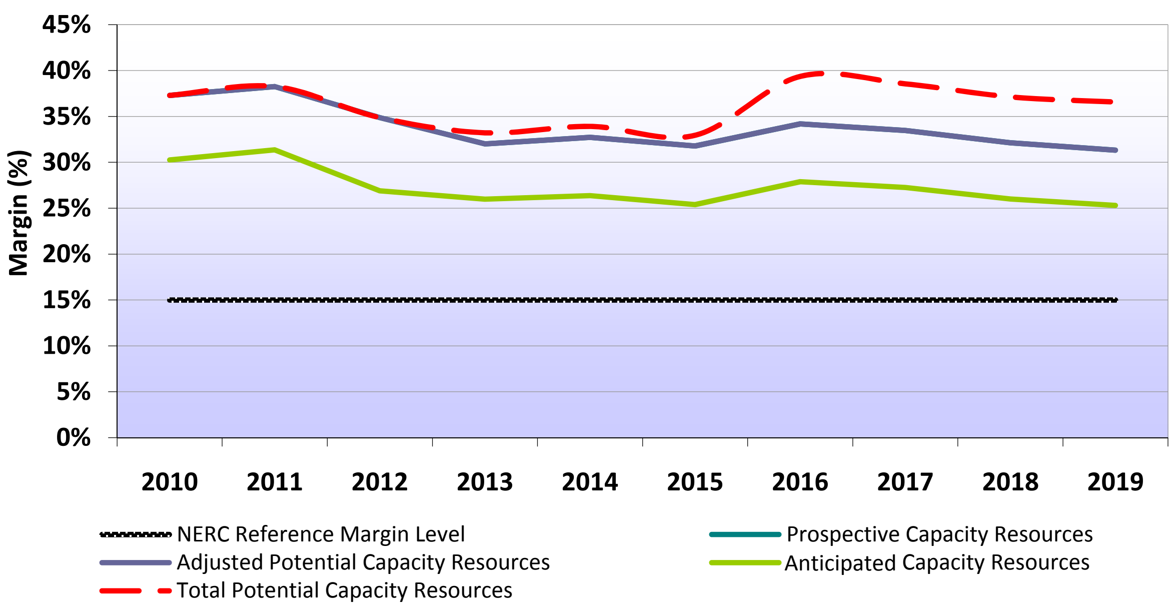
There are not a significant amount of distributed resources installed on the Southeastern system; therefore, there are no anticipated operational changes, concerns, or special operating procedures related to distributed resource integration. Demand Response programs currently in place do not negatively impact reliability. All programs are well coordinated with transmission and generation operations.

[126] NERC EOP-002 Reliability Standard; http://www.nerc.com/files/EOP-002-2_1.pdf

Reliability Assessment Analysis

Projected net reserve margins for utilities in the Southeastern subregion as reported between the years 2010 to 2019 are from 31.4 percent to 25.3 percent over the ten-year assessment period (see Figure SERC-6). There is no subregional, Regional, state or provincial reserve margin requirement for this subregion, other than mandated margins from the state of Georgia.

Figure SERC-6: Summer Peak Reserve Margin Projections



The state of Georgia requires maintaining at least 13.5 percent near-term (< 3 years) and 15 percent long-term (3 years or more) reserve margin levels for investor-owned utilities. They are reviewed on a yearly or triennial basis. Analysis has shown that load forecast error in the near term is significantly less than for the long-term. Hence, reserve margins are treated differently and are separately established for near-term and long-term planning studies. Recent analyses of demand forecasts indicate that projected reserve margins remain well above 15 percent for the next several years for most utilities in the subregion. Analyses account for planned generation additions, retirements, deratings due to environmental control additions, load deviations, weather uncertainties, and forced outages and other factors. Resource adequacy is determined by extensive analysis of costs associated with expected unserved energy, market purchases and new capacity. These costs are balanced to identify a minimum cost point which is the optimum reserve margin level.

The latest resource adequacy studies show that reserve margins for 2010 summer are forecast to be within the range of 15 percent to 34 percent for utilities within the subregion. It is not expected to drop below 15 percent in the next 10 years. Even though some utilities use purchases and reserve sharing agreements, they are not relying on resources from outside the Region or subregion to meet load. Additionally, post-peak assessments are conducted, on an as-needed basis, to evaluate system capability resulting from an extreme peak season. Information such as updates to load forecasts, outage information, fuel costs, and other inputs are re-evaluated as well. The evaluation is performed for the current year through a twenty-year planning horizon. Sensitivities addressing criteria such as impacts expected from future environmental standards or regulations are evaluated as needed.

On average for the ten-year period, 53,722 MW of internal resources[127] and 6,674 MW of capacity transactions which account for internal resources of non-reporting parties and for external resources were reported during this assessment period. These resources are considered to be able to meet the criteria or target margin level for 2010 summer.

One entity has one generating facility in the FRCC Region that is jointly owned with Progress Energy Florida. The entity has the rights to approximately 150 MW of power during summer and has firm transmission service to import it; however it is not relied upon to meet its reserve margin targets.

The fuel supply infrastructure, delivery system, and reserves are all adequate to meet peak gas demand and evade possible interruptions. Various companies have firm transportation diversity, gas storage, firm pipeline capacity, and on-site fuel oil and coal supplies to meet the peak demand. Many utilities reported that fuel vulnerability is not an expected reliability concern for the summer reporting period. The utilities have a highly diverse fuel mix to supply the demand, including nuclear, PRB coal, eastern coal, natural gas and hydro. Some utilities have implemented fuel storage and coal conservation programs, and various fuel policies to address this concern. Fuel supply policies have been put in place to ensure that storages are filled well in advance of hurricane season (by June 1 of each year). These tactics help to ensure balance and flexibility to serve anticipated generation needs. Relationships with coal mines, coal suppliers, daily communications with railroads for transportation updates, and ongoing communications with the coal plants and energy suppliers ensure that supplies are adequate and potential problems are communicated well in advance to enable adequate response time. Energy-only resources and transmission-limited resources are not commonly included in reserve or capacity margin calculations or in resource adequacy assessments.

RPSs are not commonly implemented or mandated within the subregion, but companies are continually evaluating all types of resources including renewable capacity portfolios. Other than hydro-electric, renewable resources are not yet used due to little opportunity for variable resources driven by the unavailability of sufficient wind and solar resources. Biomass, in the form of landfill gas and wood waste, has been introduced in limited quantities. Lack of financing also appears to be a hurdle for renewable resource developers causing project cancellations despite regulatory incentives. Due to the uncertainty driven by the cancellations, some companies limit the proposed renewable project capacity amount represented in their integrated resource plan. Due to the small amount of proposed renewable capacity, their impact to the total capacity of the system is negligible. As the amount increases and operating experience is gained, integrated resource plans and resource adequacy analyses will be appropriately adjusted to account for forced outage rates, availability, etc.

Most utilities in the subregion do not include Demand Response effects in their resource adequacy assessments, but those that do consider them include these programs as follows. RTP (real time pricing)

[127] Internal resources are capacity which are reporting and located within the subregion.

load response was reported to be divided into two categories: standard and extreme. Standard RTP by historical observation is that load which is expected to be reduced at weather-normal peaking-price levels and is deducted from the peak demand in the resource adequacy analysis. Extreme RTP is expected to reduce at higher pricing levels than expected for the standard RTP and is subdivided into separate blocks, each having an amount and a price trigger determined by analysis. The capacity equivalent, relative to the benefit of a combustion turbine, of Extreme RTP is included in the resource analysis as a capacity resource. Interruptible load is evaluated to determine its capacity equivalent, based on the contract criteria, relative to the benefit of a combustion turbine. The resulting value is included in the resource analysis as a capacity resource limited by the contract callable terms: hours per day, days per week, and hours per year. In addition, no unit retirements are projected during this study period.

A 2,250 MW UVLS scheme has been installed in north Georgia. The scheme was installed to help meet three-phase faults with breaker failure contingencies performed for the reliability assessment of the system. No plans to install more schemes have been reported for the period.

There are no plans to install SPS or remedial action schemes in lieu of bulk power transmission facilities.

To prepare for catastrophic events, utilities within the subregion use various tactics. Processes and guidelines within coal, natural gas, and transmission usage were areas that companies saw as the most critical. To address coal, some resource adequacy studies around the subregion evaluate the ability to meet peak demand while considering the capability and historic, probabilistic limitations of the import interfaces. A special scenario of the study is performed to assess the ability of the system to sustain a credible, worst-case catastrophic pipeline failure event. Natural gas is assessed by some utilities through firm gas supply contracts with over 25 natural gas suppliers from multiple Regions, including the Gulf of Mexico, mid-continent, and LNG. In addition, over 100 NAESB[128] contracts with suppliers and contracts with natural gas storage service providers ensure protection against short-term supply interruptions. The gas pipeline companies and gas storage providers communicate any facility outages or issues in advance with company gas employees through informational postings on their web sites or through e-mail. As described above, companies regularly perform transmission studies considering loss-of-pipeline, extreme event (TPL-003 and 004), and infrastructure security studies. Various contracts (master interchange and reserve sharing agreements, interruptible load contracts, reserve margins, dual fuel capabilities, etc.) are in place to provide assistance during emergency conditions. The purpose of them is to address vulnerability to catastrophic events and the development of appropriate mitigation plans. The general conclusion is that the system is capable of weathering many potential catastrophic events with minimal impacts on neighboring systems.

To minimize impacts on the system, utilities annually perform Regional assessments of the transmission system. Reliability concerns are addressed through the development of projects for a ten-year period. Transmission expansion plans include projects that exceed the requirements of current reliability

[128] North American Energy Standards Board

standards[129]. The inclusion of these projects will assure that the reliability concerns are met during the next 10 years.

The Southeastern subregion does not have subregional criteria for dynamic, voltage, or small signal stability; however, various utilities within it perform individual studies and maintain individual criteria to address any stability issues. A criterion such as voltage security margins of five percent or greater (in MW) has been put in place within various utility practices. To demonstrate this margin, the powerflow case must be voltage stable for a five percent increase in demand (or interface transfer) over the initial demand in the area (or interface) under study with planning contingencies applied. Studies are made each year for the upcoming summer and generally for a future year case. The studies did not indicate any issues that would impact reliability during 2010 summer. Other utilities use an acceptable voltage range of 0.95 p.u. -1.05 p.u. on their transmission system. During a contingency event, the lower limit decreases to 0.92 p.u., with the upper limit remaining the same. The acceptable voltage range is maintained on the system by dispatching reactive generating resources and by employing shunt capacitors at various locations on the system. To address dynamic reactive criterion, some utilities follow the practice of having a sufficient amount of generation on-line to ensure that no bus voltage is to be subjected to a delayed voltage recovery following the transmission system being subjected to a worst-case, normally cleared fault. Studies of this involve modeling half of the area demand as small motor load in the dynamics model. Prior to each summer, an operating study is performed to quantify the impact of generating units in preventing voltage collapse following a worst-case, normally cleared fault. The generators are assigned points, and the system must be operated with a certain number of points on-line depending on current system conditions including the amount of power plants on-line and the current transmission system configuration. The study is performed over a range of loads from 105 percent of peak summer demand down to approximately 82 percent of peak summer demand conditions.

Utilities within the subregion have many smart grid technologies and applications being used. Smart Grid investments have been made over many years to help maintain strong reliability. Some of these technologies enable the grid to communicate potential problems and minimize many disturbances. Others have the ability to take corrective action, restoring service to customers. Others provide system operators with the real-time information and diagnostic tools needed for rapid decision-making, allowing utilities to avoid outages or at least minimize their impact. Utilities continue to explore the viability of new technologies to continue to expand the use of intelligent electronic devices for monitoring, improved reliability, and optimum performance.

The state of the economy has resulted in much lower demand forecasts, which may delay the need for certain generation/transmission projects. However, the effects of any generation/transmission project slow-downs, deferrals, or cancellations would not negatively affect system reliability. As mentioned above, several of the proposed climate legislations or anticipated EPA regulation could lead to potential unit retirements within the planning horizon. Entities continue to evaluate the reliability impacts of

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[129] NERC Reliability Standards; http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf

these concerns, and solutions are being developed to address them. Overall, this is not seen as a reliability concern. However, if the impact of legislation and regulation results in the inability to distribute significant amounts of existing generation across the Region, then the ability to procure and/or construct replacement generation within a given timeframe could present a reliability concern.

Subregion Description

The Southeastern subregion covers the majority of Alabama, Georgia, parts of Mississippi and Florida.

VACAR SUBREGION

DEMAND

The 2010 summer aggregate Total Internal Demand forecast for the utilities in the VACAR subregion is 63,456 MW and the forecast for 2019 is 74,379 MW. This year's forecast CAGR for 2010 to 2019 is 1.72 percent. This is lower than last year's forecast growth rate of 1.84 percent. Changes in growth rates are due to an economy that is forecast to grow at a slower rate. Adjustments have been made to reflect slowed growth and moderate increases in wholesale sales.

Utilities in the subregion use a variety of methods to predict load. These may include regressing demographics, specific historical weather assumption or the use of a Monte Carlo simulation using multiple years of historical weather. The economic recession is expected to cause slowed load growth and a significant increase in load management within this subregion. One method uses three weather variables to forecast the summer peak demands. The variables are (1) the sum of cooling degree hours from 1 p.m. to 5 p.m. on the summer peak day, (2) minimum morning cooling degree hours per hour on the summer peak day and (3) maximum cooling degree hours per hour on the day before the summer peak day. Economic projections can be obtained from Economy.com, an economic consulting firm, and through the development of demand forecasts.

The utilities in the subregion have a variety of programs offered to their customers that support Energy Efficiency and Demand Response. Some of the programs are current Energy Efficiency and DSM programs that include:

- interruptible capacity
- load-control curtailing programs
- residential air conditioning direct load
- energy products loan program
- standby generator control
- residential time-of-use
- Demand Response programs (interruptible and related rate structures)
- Power Manager PowerShare conservation programs
- residential Energy Star rates
- Good Cents new home program
- commercial Good Cents program
- thermal storage cooling program
- H20 Advantage water heater program
- general service and industrial time-of-use
- hourly pricing for incremental load interruptible, etc.

These programs are used to reduce the affects of summer peaks and are considered part of the utilities' resource planning. The commitments to these programs are part of a long-term, balanced energy strategy to meet future energy needs. Demand Response will be measured by statistical models that identify the difference between the actual consumption and the projected consumption absent the curtailment event. With the exception of NCUC (North Carolina Utilities Commission) guidelines stated in the Reliability Assessment Analysis section, VACAR entities have not adopted renewable portfolio standards for these resources.

To assess demand variability, some utilities within the subregion use a variety of assumptions to create forecasts. These assumptions are developed using economic models, historical weather (normal/extreme) conditions, energy consumption and demographics. The forecast is based on an analysis of historical events that occurred over the previous 10 years and on assumptions regarding the future. These assumptions relate to key factors known to influence energy consumption and peak demand (*i.e.* economic activity, price of electricity, weather conditions, and local area demographics). Non-weather sensitive industrial energy forecasts may be developed subjectively based on historical trends and information provided by individual industrial customers. Projections of peak demand are developed for the summer season and are based on equations that incorporate total energy requirements and long-term peak demand. In addition to the peak-demand base-case forecast, high and low-range scenarios are developed to address uncertainties regarding the future and extreme weather conditions. Simulations for both energy and peak demand address the uncertainty associated with those factors and are included in econometric models. Results from the simulations are used to produce probabilistic high and low-range forecasts. Model inputs include probability distributions of personal income, heating and cooling degree-days, and peak-day average temperatures. Outputs for each year of the forecast period include energy and peak-demand distributions including projections from the 0 percent to 100 percent probability levels in increments of 5 percent. The high and low-range forecasts are represented by the 5^{th} and 95^{th} percentiles. Results provide peak demand estimates for given temperatures and the probabilities that peak demand will rise or fall to specific levels around the base-case forecast. Daily forecasts may be prepared using software such as NELF (Neural Electric Load Forecaster), which take into account daily temperature forecasts for service areas. Daily load forecasts are used to perform next day studies and daily switching studies. Overall, there have been no changes to demand forecasting methods for the period.

Generation

Companies within the subregion expect to have the following aggregate capacity on-peak. This capacity is expected to help meet demand during this period. Variable capacity is not commonly planned in peak maximum capacity calculations. However, some entities evaluate these resources the same as all generation resources. These resources may be given a reduced capacity contribution for reserve margin based on an estimated hourly energy profile.

Table SERC-9: VACAR Capacity Breakdown

Capacity Type	2010 (MW)	2019 (MW)
Existing-Certain	71,679	73,568
Nuclear	14,869	15,165
Hydro/Pumped Storage	9,779	9,779
Coal	25,036	25,223
Oil/Gas/Dual Fuel	21,515	22,924
Other/Unknown	262	259
Solar	0	0
Biomass	218	218
Wind	0	0
Existing-Other	1,780	1,780
Existing-Inoperable	34	34
Future-Planned	41	8,562
Future-Other	0	0
Conceptual	29	4,436
Wind	0	30
Solar	0	2
Hydro	0	0
Biomass	29	65

In order to identify the process used to select resources for reliability analysis/reserve margin calculations for future and Conceptual resources, VACAR resource planning departments approach both quantitative analysis and considerations to meet customer energy needs in a reliable and economic manner. Quantitative analysis provides insight on future risks and uncertainties associated with fuel prices, load-growth rates, capital and operating costs, and other variables. Qualitative perspectives such as the importance of fuel diversity, the company environmental profile, the stage of technology deployment, and Regional economic development are also important factors to consider as long-term decisions regarding new resources. In light of the quantitative issues, several entities have developed a strategy to ensure that the company can meet customers' energy needs reliably and economically while maintaining flexibility pertaining to long-term resource decisions.

Other entity processes secure resources needed further into the future through RFPs or designated network resources (backed by firm resources). Future amounts of required reserves may be compared to the amount of current and planned generation on entity systems to gauge the need for future generating units. Others participate in RPM (reliability pricing model) capacity markets. Only Existing-Certain and Future-Planned capacity may be counted towards meeting the reserve requirement within the PJM area. Conceptual capacity is not counted until an Interconnection Service Agreement is executed. All proposals for new capacity come through the Regional transmission expansion process to determine the required transmission expansion if necessary. Resources are evaluated using a wide range of criteria, including commercial availability, technical feasibility and cost.

Confidence factors are not commonly used to evaluate Conceptual resources. While some utility resource plans contain undesignated resources in future years, these undesignated resources may be supplied by new generation, purchases, uprates, DSM or a combination of these resources. Other entities use calculations of commercial probability. This method uses historically gathered information to assign probabilities to each milestone category (signed ISA, submitted, etc.). The probability percentages are then applied to the amount of queued resources in each category to determine a commercial probability for aggregate resources for each future year.

Other alternative processes define Conceptual resources by executed capacity agreements or by self-built generation within the approval stages for construction. Rigorous studies such as feasibility, system impact, and facility studies must be complete as part of interconnection processes before a resource can be categorized as Conceptual.

Capacity Transactions on Peak

Utilities within VACAR reported the following imports and exports for the ten-year assessment period. These sales and purchases are external and internal to the Region and subregion and help to ensure resource adequacy for the utilities. All purchases are backed by firm contracts for both generation and transmission and are not considered to be based on partial path reservations.

Table SERC-10: VACAR Purchases and Sales			
Transaction Type	2010 Summer (MW)	2014 Summer (MW)	2019 Summer (MW)
Firm imports (external subregion)	2,936	1,471	1,504
Firm exports (external subregion)	1,637	1,382	1,382
Expected imports (external subregion)	0	0	0
Expected exports (external subregion)	0	0	0
Provisional imports (external subregion)	0	0	0
Provisional exports (external subregion)	0	0	0

Transmission

Delays with the above in-service dates have not been identified as a risk. If delays occur that result in reliability concerns, mitigation procedures would be developed accordingly. Mitigating measures could include re-dispatch of generation, operating procedures, and special protection schemes. In addition, no significant changes or reliability concerns have been identified since last year's assessment.

Utilities in the subregion have employed SVC technology in the past and are considering its use in the future. Other utilities are actively investigating potential application of smart grid technology for future implementation. One utility is installing a 300 MVAr SVC scheduled to be in service June 2012.

Operational Issues

Utility transmission planning departments within the subregion have not identified any potential or systemic outages that may impact reliability during the next 10 years. Steps are taken to coordinate and complete scheduled generator maintenance ahead of peak demand periods. Recent studies take into account that existing generation is expected to be available during the peak demand periods and no transmission limitations are expected to occur. Daily reliability studies are also performed to ensure the transfer capabilities are sufficient to support external power flows across the transmission system.

In the event that peak demand is higher than forecast, some entities reported they would defer elective maintenance at generating stations that do not affect unit availability or capacity, but could pose a trip risk. Entities strive to meet customer energy demands either with available generating resources, power purchases, or with planned load-management programs. If customer demand cannot be met by these measures, emergency actions such as voltage reductions and manual load shed (as a last resort) are then used.

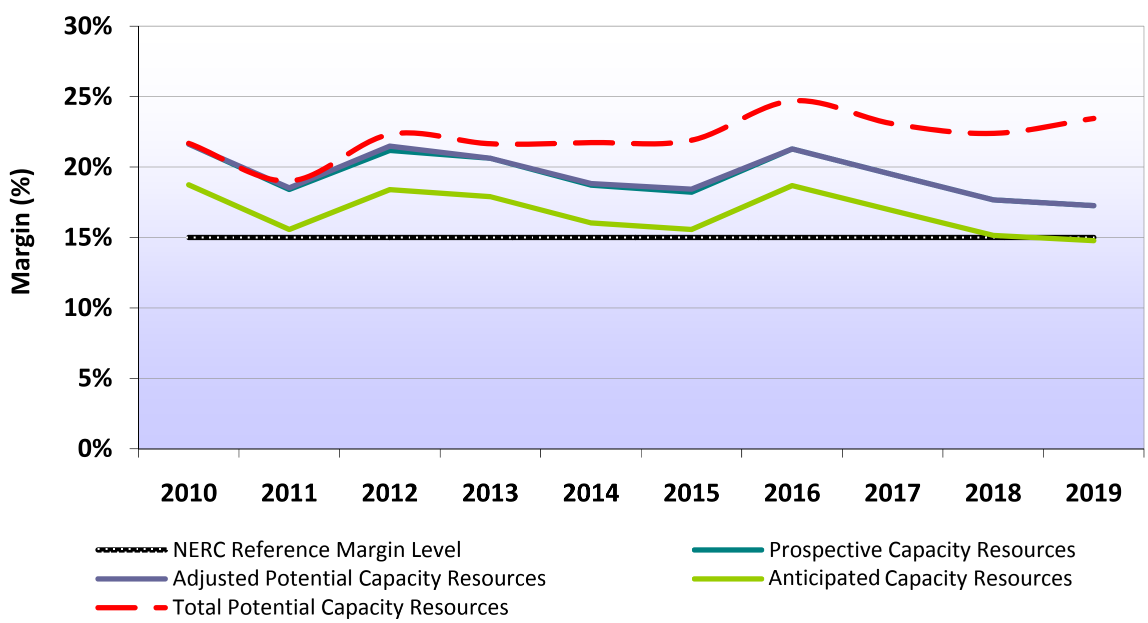
There are no anticipated local environmental and/or regulatory restrictions that could potentially impact reliability. To ensure minimum impact to the system, PJM requires its members in VACAR to place generation resources into the "maximum emergency" category if environmental restrictions limit run hours below pre-determined levels. Max emergency units are the last to be dispatched.

Since the amounts of distributed and variable generation are very small and entities within the subregion hold a diverse amount of resources, special operating procedures are not needed for the integration of variable resources or to mitigate concerns resulting from high levels of Demand Response resources.

Reliability Assessment Analysis

Projected net reserve margins for utilities in the subregion as reported between the years 2010 to 2019 are from 18.7 percent to 14.8 percent (see Figure SERC-7). Entities continue to project margins based on load reductions due to the economy, increased DSM, significant increases in generation, and weather. Resources are projected to be adequate to meet demand for the period.

Figure SERC-7: Summer Peak Reserve Margin Projections



Utilities within the VACAR subregion do not adhere to any Regional/subregional targets or reserve margin criteria. However, some utilities within this subregion adhere to NCUC regulations. Other utilities established individual target reserve margin levels to benchmark margins that will meet the needs for peak demand. Some assumptions used to establish the individual utilities' reserve/target margin criteria or resource adequacy levels are based on prevailing expectations of reasonable lead times for the development of new generation, procurement of purchased capacity, siting of new transmission facilities and other historical experiences that are sufficient to provide reliable power supplies. Assumptions may also include levels of potential DSM activations, scheduled maintenance, environmental retrofit equipment, environmental compliance requirements, purchased power availability, or peak-demand transmission capability/availability. Risks that would have negative impacts on reliability are also an important part of the process to establish these assumptions. Some of these risks would include the deteriorating age of existing facilities on the system, significant amount of renewables, increases in Energy Efficiency /DSM programs, extended base-load capacity lead times (for example coal and nuclear), environmental pressures, and derating of units caused by extreme hot weather/drought conditions. In order to address these concerns, companies continue to monitor these future risks and make any necessary adjustments to the reserve margin target in future plans.

The LOLE (Loss of Load Expectation) standard of 1 occurrence in 10 years is also used to address reserve margin targets. Annual LOLE studies help to determine the reserve margin required to satisfy this criterion. The study recognizes, among other factors such as demand forecast uncertainty due to economics and weather, generator unavailability, deliverability of resources, and the benefit of interconnection with neighboring systems. Uncertainties are also addressed through capacity margin objectives and practices in other resource assessments at the operational level. These studies may be performed at least twice daily using input provided from generator operators. As conditions warrant, entities perform additional assessments to mitigate challenging conditions on the system.

The latest resource adequacy studies performed were reported to be completed in the winter of 2009. These studies examined resource availability for multiple years. Resource adequacy is assessed using various methods and assumptions that range from LOLE studies (1 occurrence in 10 years), loss of multiple unit studies, new environmental requirements, declining economic conditions, renewable energy, new generation technologies, rising commodity costs, forecasts for normal/severe weather cases with additional firm capacity (existing, future and outage models included) and forecast demand plans on an annual/seasonal basis. In addition, forecasts for peak demand is generally made under a variety of both weather and economic conditions under RUS 1710[130] requirements. From this analysis, resources are planned accordingly. This year's studies are expected to show the system to be adequate based on the current forecasts for demand, generation, and demand-side resources. Margins from the studies show that entities within the subregion are adequate with reserve margin percentages in the range of 15 percent. Overall, assuming that existing and planned resources are in-service, reserve margin requirements will be met for the period.

Utilities do not depend on resources from other Regions or subregions to meet emergency imports and reserve sharing requirements. On average for the ten-year period, 71,936 MW of internal resources and 1,586 MW of capacity transactions, which account for internal resources of non-reporting parties and for external resources were reported during this assessment period. These resources are considered to be able to meet the NERC reference margin level for the period.

Short-term and long-term margins are generally not treated differently in utility studies. However, some entities have procedures in place to differentiate between the two margins. In this case, short-term calculations apply to a three-year period. After three years, a commercial probability is applied to the generator interconnection queues to determine how much generation in aggregate should be applied in

[130] Electronic Code of Federal Regulations, Title 7, Chapter XVII – Rural Utilities Service, Department of Agriculture. http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&tpl=/ecfrbrowse/Title07/7cfr1710_main_02.tpl

the long-term. Overall, there is no subregion wide confidence factor to determine margins within this category.

Utilities within the VACAR area have reported that their generation facilities expect to maintain enough diesel fuel to run the units for an order cycle of fuel. Fuel supply or delivery problems during the projected time period are not anticipated. Entities have ongoing communications with commodity and transportation suppliers to communicate near-term and long-term fuel requirements. These communications take into account market trends, potential resource constraints, and historical and projected demands. These discussions are framed to ensure potential interruptions can be mitigated and addressed in a timely manner.

Exchange agreements, alternative fuel or redundant fuel supplies may also be used to mitigate emergencies within the fuel supply industry or economic scenarios. Onsite fuel oil inventory allows for seven-day operations on some units. This was considered to be ample time to coordinate with the industry to obtain adequate supplies. Contracts are in place months, and often years, into the future. Vendor performance is closely monitored and potential problems are addressed long before issues become critical.

Transmission-limited and energy-only units are not considered in reliability analysis. They are modeled when performing generator interconnection studies to check short-circuit and dynamics performance. Firm capacity resources are solely included in entity resource adequacy assessments and are either located inside the subregion or are delivered over firm transmission contracts.

As noted above, most entities do not include renewable resources in their capacity adequacy assessments. Variable renewable resources may be evaluated the same as all generation resources. These resources are given a reduced capacity contribution for reserve margin based on an estimated hourly energy profile. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation, only historic performance over the peak period is used to determine the individual unit's capacity factor.

For some utilities, renewable portfolio standards assumptions are based on recently enacted legislation in North Carolina. Overall planning requirements are based on 3 percent to 12.5 percent of the load between the years 2011 to 2021. Additional requirements within North Carolina Commission[131] state that plans should capture 25 to 40 percent of the overall demand sales must be met by Energy Efficiency starting in 2020 to 2021. Up to 25 percent of the requirements can be met with RECs (Renewable Energy Certificates). Solar requirements must consist of 0.02 to .20 percent of the load between the years of 2010 to 2018. Hog waste requirements are 0.07 to 0.20 percent in the years 2012 to 2018. Poultry waste requirements were applied by one utility’s share of total North Carolina load (~42 percent). These requirements state that 71,400- 378,000 MWh in the years 2012 to 2014 must be met by this resource. The overall requirements were applied to all native loads served by the utility (*i.e.*, both retail and wholesale, and regardless of the location of the load) and take into account the potential that a federal

[131] North Carolina Customer Energy Efficiency Programs, http://www.aceee.org/energy/state/northcarolina/nc_utility.htm

RPS may be imposed that would affect all loads. The requirement that a certain percentage must come from solar, hog and poultry waste was not applied to the South Carolina portions of load. Other entities within the state are considering the impact of contracted renewable resources in their portfolios on a case-by-case basis in order to assess and meet resource adequacy requirements and the REPS (Renewable Energy and Energy Efficiency Portfolio Standard) mandated by North Carolina State Law. PJM has stated that it will assist with the planning studies to build transmission to bring the renewable resources to the PJM market.

In general, wind resources in the VACAR subregion are concentrated in two Regions. The first is along the Atlantic coast and barrier islands. The second area is the higher ridge crests in the western portions of VACAR. Offshore wind power, an emerging technology, may provide greater potential for the Region in the future. Virginia and the Carolinas benefit from offshore wind and shallow water that is less than 30 meters deep and within 50 nautical miles of shore. Once the technology is developed and the regulatory process is established, this untapped energy source may contribute more capacity and energy production for the VACAR subregion. Utilities within VACAR will continue to monitor the progress and the cost effectiveness of this technology.

In the summer of 2008, the North Carolina General Assembly requested UNC (University of North Carolina) to study the feasibility of producing wind energy in the Pamlico and Albemarle Sounds. The study report was issued in June 2009. The North Carolina Transmission Planning Collaborative[132] intends to perform a coastal North Carolina wind sensitivity study with wind injections in locations and amounts, based on information obtained from the UNC report. The 2010 study will analyze the transmission required to deliver up to 3,000 MW of offshore wind.

To address Demand Response in resource adequacy studies, some utilities have reported that they are provided with energy and cost data forecasts for current and projected DSM programs. These assumptions have been modeled in various programs such as System Optimizer[133] and PROSYM[134]. Sensitivities on DSM energy and cost projections are performed to understand the impact of the program's implementation on total system costs and annual reserve margins. Other companies note that Demand Response is considered a capacity resource. Since additional firm capacity is secured on a seasonal basis to cover a minimum of 50 percent of the difference between the typical and severe demand forecast, Demand Response capacity resources are rarely dispatched. Demand Response may also be included in resource adequacy studies as Demand Response emergency programs. In this scenario, interrupted customers must submit data to verify their ability to interrupt up to the full claimed capacity value. Failure to submit this data may lead to financial penalties to the Demand Response provider. Overall, there have been no significant changes in the amount and availability of load management and interruptible demands since last year.

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[132] http://www.nctpc.org/pctpc

[133] http://www.ventyx.com/analytics/system-optimizer.asp

[134] http://www.ventyx.com/global/eu/analytics/market-analytics.asp

One utility reported that it has developed a timeline of projected unit retirement dates for approximately 500 MW of older combustion turbine units and 1,000 MW of non-scrubbed coal units. Various factors, such as the investment requirements necessary to support ongoing operation of generation facilities, have an impact on decisions to retire existing generating units.

Currently, the NCUC has two requirements related to the retirement of 800 MW of older coal units. The first condition granted the installation of Cliffside Unit 6, but requires the retirement of the existing Cliffside Units 1-4 no later than the commercial operation date of the new unit. The retirement of these units and other older coal-fired generating units must consider the impact on the reliability of the system and account for actual demand reductions from new Energy Efficiency and DSM programs (up to the MW level added by the new Cliffside unit). The requirement to retire older coal is also set forth in the air permit for the new Cliffside unit. Retirements are scheduled for 350 MW of coal generation by 2015, 200 MW by 2016, and an additional 250 MW by 2018. If the Commission determines that the scheduled retirement of any unit pursuant to the plan will have a material adverse impact on system reliability, the utility is prepared to seek modification of the plan. For planning purposes, the retirement dates for these additional 800 MW of older coal units are associated with the expected verification of realized Energy Efficiency load reductions, which is expected to occur earlier than the retirement dates set forth in the air permit.

Another utility filed a plan with the NCUC to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. It is projected that new generation will be built to offset a portion of the generation being retired. No reliability concerns are anticipated from either a transmission or capacity perspective because of the retirement of these units.

In order to address reliability issues in the future, utilities have considered using UVLS schemes on their system. However, none of these programs are currently installed on the system during the time of this assessment. There are no SPS or remedial action schemes in the VACAR subregion.

Utilities have addressed planning processes for catastrophic events in many ways. Some companies have procedures in place for system restoration, capacity and emergency action plans. Other companies follow the practice of maintaining several days' worth of fuel oil at facilities in the event of natural gas disruptions. Resource portfolios are also used to address the issue. Portfolios are diversified with multiple resources mitigating the impacts of a major import path disruption. Sophisticated internal real-time systems have been developed around the system to track and analyze gas pipeline issues. These systems can monitor the impact of disruptions to major pipelines or the loss of a major import path as part of a contingency analysis process. Depending on the advance notice, operating plans can be adjusted or emergency procedures can be implemented. For the projected summer peaks, reserve margins are such that loss of multiple units can be accommodated without threatening reliability.

Transmission planning practices are used in accordance with the SERC Supplement Transmission System Performance NERC Reliability Standards TPL-001 through 004[135] to test the system under stressed conditions, and have historically proven adequate to meet variations in operating conditions, forecast demand and generation availability. In addition, special transmission assessment studies are conducted as needed to assess unusual operating scenarios (*e.g.*, limitation on generation due to extended drought conditions), and then develop any mitigation procedures that may be needed. Recent studies have identified no reliability issues. Some utilities perform an operational peak self-assessment for anticipated and extreme winter/summer conditions as well as an interregional analysis in conjunction with neighbors to identify potential issues that may arise between areas. No reliability issues are expected. Tests are also done to assess various stability study criterion as well as stressed system scenarios and contingencies. Studies of this type are routinely performed, both internally and through subregional and Regional study group efforts.

Operational studies are performed regularly, both internally as well as externally. Coordinated single-transfer capability studies with neighboring utilities are performed quarterly through the NTSG. Projected seasonal import and export capabilities are consistent with those identified in these assessments. Internal operating studies are performed when system conditions warrant. No reliability issues have been identified for the period.

Stability and dynamic assessments/criteria are performed and produced on an individual company basis within the VACAR area. However, most entities participate in the VSWG (VACAR Stability Working Group) to assess annual dynamic conditions on the system. The SERC DSG will not have dynamic simulation cases completed for the 2010 dynamic data submittal year until the fall of 2010. Some utilities individually follow practices such as using a reactive power-supply operating strategy based on adopted generating station voltage schedules and electric system operating voltages managed through real-time RACE (Reactive Area Control Error) calculations. Through this operating practice, primary support of generator switchyard bus voltage schedules using transmission system reactive resources, dynamic reactive capability of spinning generators may be held in reserve to provide near-instantaneous support in the event of a transmission system disturbance. Other utilities may develop RTI (Reactive Transfer Interfaces) to ensure sufficient dynamic MVAr reserves in load centers that rely on economic imports to serve load. Day-ahead and real-time security analysis ensures sufficient generation is scheduled/committed to control pre-/post-contingency voltages and voltage drop criteria within acceptable predetermined limits. Reactive transfer limits are calculated based on a predetermined back-off margin from the last convergent case. Overall, no stability or dynamics issues have been identified as impacting reliability.

As mentioned above, utilities have employed SVC technology in the past. One utility is installing a 300 MVAr SVC scheduled to be in service June 2012. Other utilities are actively investigating the potential application of smart grid technology for future implementation.

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[135] SERC Supplement Transmission System Performance NERC Reliability Standards TPL-001 through 004; http://www.serc1.org/Documents/SERC%20Standing%20Committee%20Documents/Supplements/Transmission%20System%20Performance%20SERC%20Supplement%20(10-16-08).pdf

No reliability impacts are expected to occur from project delays or cancellations. Generally, before commitments to delay, defer or cancel projects are made, a careful review of the potential impacts resulting from the scheduled change from prior plans is conducted. As such, when these changes are implemented, reliability impacts are known and are considered negligible.

To minimize reliability concerns on the system, entities regularly study and review annual/seasonal assessments. These assessments serve to develop a seasonal strategy for maintaining adequate system operating performance. Construction schedules are predetermined to avoid impacts to transmission system reliability, but unplanned delays to these schedules may result in transmission element outages that extend into the winter season. Should construction delays be unavoidable, operational risks and steps to mitigate these risks will be evaluated. Overall, there are no other anticipated reliability concerns that have been identified for the period.

SUBREGION DESCRIPTION

The VACAR subregion includes 11 electric systems located in North Carolina, South Carolina and Virginia.

SOUTHWEST POWER POOL (SPP)

EXECUTIVE SUMMARY

The Southwest Power Pool, Inc. Regional Entity's (SPP RE) year-by-year demand for the 2010-2019 assessment period is projected to be approximately 3 percent lower than the 2009-2018 assessment period. For 2019, the SPP RE's Total Internal Demand is projected to be 49,739 MW, with Total Internal Capacity resources of 63,118 MW. Approximately 4,800 MW of Existing-Certain resources were added since the last reporting year. The SPP RE expects to add 5,794 MW of Future, Planned resources during the assessment timeframe. Although no significant variable capacity additions or unit retirements were reported, the SPP RTO currently has approximately 37,000 MW of generation (mostly wind) in the Generation Interconnection queue.

The SPP RE's minimum capacity margin requirement is 12 percent, which translates to a reserve margin of 13.6 percent[136]. For 2010-2019 assessment period, the reserve margin for the SPP RE Region - based on Existing-Certain and Net Firm Transactions - is 25.2 percent in 2010, which drops to 7.9 percent in 2019. After considering Deliverable Capacity Resources, the SPP RE's reserve margin is 28.3 percent in 2010, which drops to 19.7 percent in 2019. With the addition of Prospective Capacity Resources, the SPP RE's reserve margin is 38.9 percent in 2010 and drops to 28.9 percent in 2019. No known reliability concerns are identified for the 2010-2019 assessment period, as the targeted reserve margin is above the required level.

Table SPP-1: SPP Regional Profile

	2010	2019
Total Internal Demand	43,395	49,739
Total Capacity	57,324	63,117
Capacity Additions	0	5,793
Demand Response	418	492

Four major transmission projects have gone into service since the 2009 LTRA. Three of the four projects are lines operated at 230 kV and one is 345 kV; the 345 kV project is in Oklahoma and the Texas Panhandle. A number of 115–345 kV transmission lines are projected to be added to the SPP RTO grid during the assessment timeframe: seven are under construction, 61 planned, and 22 Conceptual. There are no known transmission reliability concerns with these projects in service.

In anticipation of a surge in renewable resources on the western part of its grid, the SPP RTO completed the Wind Integration Task Force Study in early 2010. This study reinforced the criticality of coordinating transmission expansion plans with plans for building infrastructure to accommodate wind energy. Study recommendations will allow SPP to prepare for continued growth in the Region's renewable wind resources. The study recommended significant bulk EHV transmission additions (230 kV, 345 kV and/or 765 kV) for a high wind scenario. If the needed transmission upgrades were completed, there would be

[136] The SPP Criteria are in the Governing Documents folder of the SPP.org *Documents and Filings* library. A link is at the top of the Org Groups page.

no significant technical barriers or reliability impacts to integrating wind energy levels up to 20 percent. For the near-term, the study identified the need to develop a process for determining what generating units are used throughout the Region, explicitly addressing the uncertainty associated with wind forecast errors. The implementation of a centralized wind energy forecasting system was also recommended.

In April 2010 the SPP Board of Directors and Members Committee approved for construction five "priority" high voltage electric transmission projects estimated to bring benefits of at least $3.7 billion to the SPP Region over 40 years. The projects will improve the Regional electric grid by reducing congestion, better integrating SPP's east and west Regions, improving SPP members' ability to deliver power to customers, and facilitating the addition of new renewable and non-renewable generation to the electric grid. [137] The Priority Projects were approved pending a favorable ruling by FERC on SPP's new Highway/Byway cost allocation method, which was approved by FERC in June 2010[138]

INTRODUCTION

Southwest Power Pool, Inc. (SPP) operates and oversees the electric grid in the southwestern quadrant of the Eastern Interconnection. In addition to serving as a NERC Regional Entity, SPP is a FERC-recognized Regional Transmission Organization (RTO). The SPP RTO footprint includes all or part of nine states[139]. In April 2009, Nebraska Public Power District, Omaha Public Power District, and Lincoln Electric System became members of the SPP RTO. The entities are now participating in SPP's wholesale energy market, and SPP performs services for them including transmission planning, reliability coordination, and tariff administration. The Nebraska organizations still belong to the Midwest Reliability Organization Regional Entity, which will continue to perform their Reliability Assessments.

The SPP RTO anticipates consistent but slow growth, compared to the base forecast, in demand and energy consumption over the next ten years. Sufficient generation capacity using Anticipated resources is forecasted to be available in SPP throughout the planning horizon to meet native network load needs, with Certain generation resources meeting minimum reserve margins until 2015.

DEMAND

According to the most recent forecasted data, the projected compound annual rate of growth for peak demand in the SPP RE Region over the next ten years is 1.3 percent. In the 2009 LTRA report, the projected annual growth rate for the SPP Region over the ten year period was 1.1 percent; there has been a slight increase in the demand growth forecast. The SPP RTO has 21 reporting members who annually provide a ten–year forecast of peak demand and net energy requirements. These forecasts are used to develop an overall non-coincident SPP RTO forecast. The forecasts are developed in accordance with generally recognized methodologies and in accordance with the following principles:

[137] A Priority Projects webpage is in the Engineering and Planning section of SPP.org.

[138] Visit the About Us page of SPP.org and open the Newsroom to read the June 17 Highway/Byway news release.

[139] To read more about the differences between the SPP RE and SPP RTO footprints, open the Footprints document on the SPP.org Fast Facts page.

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

Although actual demand is very dependent on weather conditions and typically includes interruptible loads, forecasted Net Internal Demands are based on 10-year average summer weather, or 50/50 weather. Some SPP RE members determine peak forecast based on a 50 percent confidence level, as approved by their respective state commission(s). This means the actual weather on the peak summer day is expected to have a 50 percent likelihood of being hotter or a 50 percent likelihood of being cooler than the weather assumed in deriving the load forecast. The SPP RTO does not develop load forecasts based on a 90/10 weather scenario, but has a 13.6 percent reserve margin requirement to address this uncertainty.

To quantify peak demand uncertainty and variability due to extreme weather, economic conditions, and other variables, the SPP RTO formed a Bandwidth Working Group. This group produced the Demand and Energy Bandwidth Report[140], which supports the current predicted growth rates and allows for up to a 1.2 percent variation from the base demand forecast in current and future predictions through the year 2012. The report also determined the 13.6 percent reserve margin is adequate to cover any extreme load for the SPP RE footprint. SPP anticipates this trend will continue for the remaining study period, and is continuing analysis for predictions beyond 2012.

These capacity or reserve margin projections include the effects of demand–side response programs, such as direct–control load management and interruptible demand. The SPP RTO does not have an organized Demand Response program at this time, but it is expected that over the next ten years, interruptible demand relief will increase from 418 MW to 492 MW. These Demand Response values are based on predictions using historical data and trends; they do not reflect increased Demand Response as directed by FERC in the evolution of SPP's market design.

GENERATION

For the 2010-2019 assessment period, the SPP RTO projects to have 52,489 MW Existing-Certain Capacity; 4,546 MW Existing-Other Capacity; 289 MW Existing-Inoperable; 5,793 MW Future Capacity; and 29,243 MW Conceptual resources in service or expected to be in service during the assessment timeframe. The Existing-Certain Capacity amount from renewable plants is 237 MW (wind), 2,335 MW (hydro), and 5 MW (biomass). Existing-Other Capacity from renewable plants (mostly wind) is 2,547 MW. Planned Capacity for 2019 from renewable plants is 119 MW. These reported renewable resource additions in the SPP RTO do not reflect: merchant wind farm development in process within SPP,

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[140] spp.org/publications/BWG_Report_2003.pdf

incremental needs which may result from Renewable Electricity Standard mandates within the SPP Region, or public pronouncements for additional renewable expansion by SPP RTO members. The SPP RTO has requests to connect approximately 37,000 MW of generation (mostly wind) to the SPP RTO grid via the Generation Interconnection queue; 28,507 MW are Conceptual.

Conceptual capacity resources forecasted for 2010-2019 are projected to be 29,243 MW. Variable generation of 28,807 MW nameplate capacity composes the majority of the Conceptual resources. The other 436 MW are listed as gas, oil, or undetermined. SPP Criteria Section 12.0 discusses capacity values and how they are calculated for the Region based on a wind farm's historical performance. The SPP RE applies a 10 percent confidence level to all Conceptual capacity unless otherwise reported by SPP members.

For Future and Conceptual capacity resources, the SPP RTO uses the Generation Interconnection and Transmission Service Request study processes as defined in the SPP Open Access Transmission Tariff [141] (OATT). According to the OATT, when the interconnection request is submitted, the interconnection customer must request either energy resource interconnection service or Network Resource interconnection service. Any interconnection customer requesting Network Resource interconnection service may also request that it be concurrently studied for energy resource interconnection service, up to the point when an interconnection facility study agreement is executed. Interconnection customers may then elect to proceed with Network Resource interconnection service or to proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed. Members that report to the SPP RE are reporting their Future, Planned, and Conceptual resources; however, SPP is including active requests that are currently in the generation queue to be studied.

Capacity Transactions on Peak

A small portion of SPP RE capacity or reserve margin depends on purchases external to the SPP RE Region. For 2010-2019 there are 1,976 MW (ten-year average) of transactions purchased external to the SPP RE Region; these are backed by firm generation and transmission reservations. There are 105 MW of firm delivery service from Western Electricity Coordinating Council, administered under Xcel Energy's OATT.

The SPP RE has 1,148 MW of firm sales external to the SPP RE Region based on a ten-year average; these are backed by firm generation and transmission reservations. SPP does not have expected or provisional transactions for neither imports nor exports. All external transactions are firm transactions.

Transmission

The SPP Transmission Expansion Plan (STEP)'s 10-year reliability assessment establishes transmission needed to meet forecasted load and all firm long-term transmission service for the next ten years. The STEP includes a reliability assessment with different scenarios of firm transmission being sold in various directions. In addition to the STEP, the SPP RTO performs various other analyses to comply with NERC Transmission Planning standards.

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[141] The Open Access Transmission Tariff is in the Governing Documents folder of the SPP.org *Documents and Filings* library. A link is at the top of the Org Groups page.

The SPP RTO is transitioning from the STEP planning process to a new Integrated Transmission Planning (ITP) process, which will improve and integrate several existing processes. The EHV Overlay, Balanced Portfolio, and Reliability Assessment processes will transition to the ITP. The Generation Interconnection and Aggregate Study processes will not be integrated into the ITP, but are expected to be simplified. The ITP will determine what transmission is needed to maintain electric reliability and provide near- and long-term economic benefits to the SPP Region. The ITP is an iterative three-year process that includes 20-Year, 10-Year, and Near-Term Assessments.

There are no known concerns about meeting target in-service dates for reliability projects that have been approved by the SPP Board. Assuming these projects come on line as scheduled, there are no known transmission constraints that could affect the reliability of the SPP transmission grid. The SPP RTO relies heavily on its Project Tracking process[142] to track projects and ensure they meet their issued timelines. If a project's timeline is extended, the SPP RTO will conduct a study to address any reliability issues associated the extension.

The Woodward District EHV to Tuco 345 kV line from Oklahoma to the Texas Panhandle, scheduled to be in service in 2014, will address some of the reliability issues in the local area as discussed in last year's LTRA. There is no significant substation equipment listed at this time.

In April 2010 the SPP Board approved for construction $1.14 billion worth of Priority Projects[143] to be constructed during the assessment timeframe. These projects will improve the Regional electric grid by reducing congestion, better integrating SPP's east and west Regions, improving SPP members' ability to deliver power to customers, and facilitating the addition of new renewable and non-renewable generation to the electric grid.

OPERATIONAL ISSUES

In the near term, SPP is coordinating the mitigation of operating concerns in an area of southern Louisiana called the Acadiana Load Pocket. This area has constraints on the transmission system, and the local utilities have fewer options for managing constraints due to transmission and generation limitations. In its role as Reliability Coordinator, SPP is closely coordinating emergency operating plans and transmission system maintenance among all affected Balancing Authorities, Transmission Operators, and Load Serving Entities. Construction is underway on additional transmission into the Acadiana Load Pocket area, which is scheduled to be completed by 2012.

As more wind generation is built in the western part of the SPP RTO grid, the organization will continue to implement operating procedures to address any reliability issues. Due to wind's variable nature, the penetration of wind generation in the western half of the SPP footprint could have a significant impact on operations. Several avenues are being explored to provide transmission outlets for this wind energy during the next ten years, including SPP's Wind Integration Task Force and Priority Projects. However, the operational impacts of wind generation to regulation and control performance are still unknown. As

[142] The Engineering and Planning section of SPP.org has a page on Project Tracking

[143] Visit the About Us page of SPP.org and open the Newsroom to read the April 27 Priority Projects news release

the penetration rate of variable generation grows, further study will be required to mitigate any issues that arise. The SPP RTO is investigating mitigation measures for integrating more wind into the SPP RE footprint, such as increasing operating reserves and implementing Regional variable resource forecasting. Operating procedures specific to individual variable resources are developed when such a need is identified due to transmission constraints.

Additional data collection and situational awareness has been implemented to begin assessing regulation and spinning reserve needs. The SPP RTO completed the Wind Integration Task Force Study[144] in January 2010, indicating that the SPP RTO would need significant transmission addition to accommodate 10 percent or higher wind capacity. The SPP RE projects to have approximately four percent of installed wind capacity on the grid for the assessment timeframe that can be counted towards the reserve margin. A significantly large percentage of wind is available in the SPP wholesale energy market for energy only purchase.

Individual Balancing Authorities in the SPP Region can take measures to decrease demand. Such measures may include but are not limited to: interruptible load, curtailment of exports, and public appeals.

The SPP RTO worked with AMEC and Southwestern Public Service (SPS)/Xcel Energy staff to investigate the operational impacts of increased wind penetration to secure reliable operations within the SPS area. Due to significant existing, approved, and requested wind farm development, constraints must be resolved in the near-term before major transmission capability can be installed to improve internal and interface capabilities. The recently completed AMEC study for spring 2010 conditions focused on operations and reliability, and did not investigate the economics associated with planned and potential wind development within and surrounding the SPS Balancing Authority. The study leveraged the National Renewable Energy Lab's wind data for 2004-2006 to simulate future scenarios for 2010. Without considering proactive wind curtailments as an option, the study concluded that operating margins within SPS would be jeopardized as wind farm development approached 1,100 - 1,200 MW. This is only slightly above existing wind farm levels, with more being built and another 2,000 MW of approved wind Interconnection Agreements. SPS is working with SPP to finalize operating procedures and communicate them to wind developers as a near-term solution. Consolidating the SPP RTO's Balancing Authorities will help facilitate wind integration in the Region, but additional changes to the SPP OATT, interconnection agreements, operating procedures, and market design may be required to maintain adequate operating margins within SPS and other portions of SPP as wind development continues.

According to SPP RTO operational staff, there are no known operational changes/concerns resulting from distributed resource integration, and SPP does not anticipate any reliability concerns as a result of Demand Response resources.

[144] Access the Wind Integration Study from the Org Groups page of SPP.org, Wind Integration Task Force section

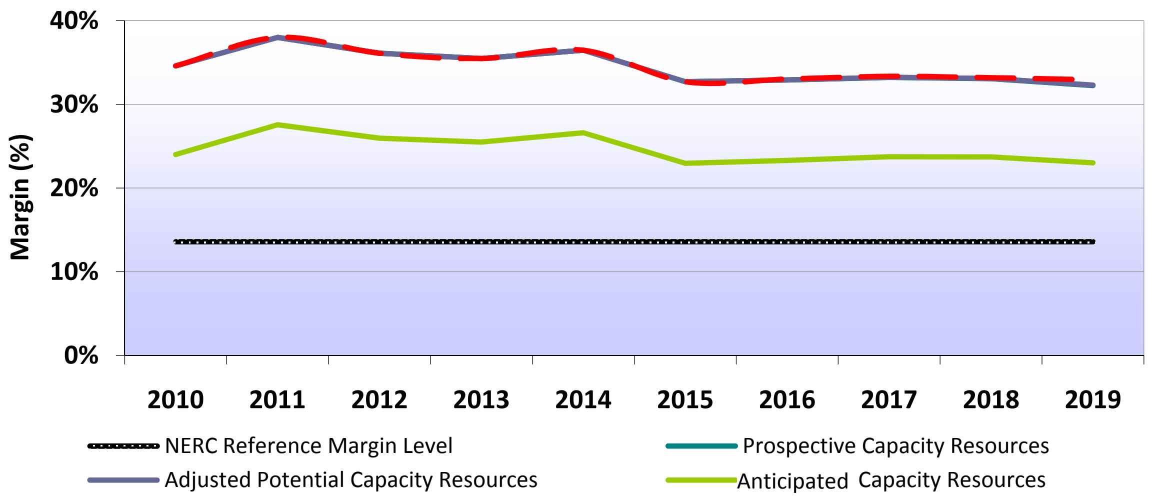
SPP RTO operations staff noted that carbon emission limitations would drastically change day-to-day generation dispatch and reduce the capability margin within SPP. Currently, the SPP RTO has a substantially diverse mix of generation capacity and a sufficient expected reserve margin such that no reliability impacts are foreseen.

Reliability Assessment Analysis

For 2010–2019, the forecasted reserve margin based on Existing-Certain capacity for 2010 is 23.1 percent; it drops to 10.7 percent in 2019. SPP Criteria requires SPP members to meet a 12 percent capacity margin, which translates to a 13.6 percent reserve margin. These margins are also expected to cover a 90/10 weather scenario.

The SPP RE annual reserve margin, based on Anticipated Capacity Resources, is projected to be above the target margin of 13.6 percent for the assessment period. Existing-Certain Capacity and Net Firm Transactions are adequate to meet the reserve margin requirement until 2015 (Figure SPP-1).

Figure SPP-1: Summer Peak Reserve Margin Projections



The SPP RTO is performing a Loss-of-Load Expectation (LOLE) and Expected, Unserved Energy study for 2016. Results of this study are expected during summer 2010. The study will evaluate the need to adjust SPP's 12 percent Regional capacity margin or 13.6 percent reserve margin, and will estimate the reserve margin required to achieve an LOLE of no more than one occurrence in 10 years. Based on the LOLE study performed by SPP RTO staff in 2009 for summer 2010, the capacity or reserve margin requirement for the SPP RTO remained unchanged. The 12 percent capacity margin and 13.6 percent reserve margin requirements are also checked annually in the EIA-411 reporting, as well as through supply adequacy audits of Regional members conducted every five years by the SPP RTO. The last supply adequacy audit was conducted in 2007, with the next audit planned for 2012.

SPP defines firm deliverability as electric power intended to be continuously available to buyers even under adverse conditions; *i.e.*, power for which the seller assumes the obligation to provide capacity (including SPP-defined capacity margin) and energy. Such power must meet the same standards of reliability and availability as that delivered to native load customers. Power purchased can be considered firm only if firm transmission service is in place to deliver the power to the load serving member. SPP does not include financial firm contracts in this category. Existing long-term firm delivery is ensured by provisions in the SPP Transmission Expansion Plan, while new long-term firm delivery is ensured by Aggregate Transmission Service Studies. These procedures are included in attachments O and Z1 in the SPP OATT.

SPP RTO members, along with neighboring members such as Entergy from the SERC Region, have formed a Reserve Sharing Group. Members of this group receive contingency reserve assistance from other SPP Reserve Sharing Group members. SPP's Operating Reliability Working Group sets the minimum daily contingency reserve requirement for the SPP Reserve Sharing Group. The SPP Reserve Sharing Group maintains a minimum first contingency reserve equal to the generating capacity of the largest unit scheduled to be online. SPP RTO does not treat short and long term reserve margin requirements differently.

Due to the SPP RTO's diverse generation portfolio, there is no concern about the fuel supply being impacted by the extremes of summer weather during peak conditions. If a fuel shortage is expected, SPP RE members are expected to communicate with SPP operations staff in advance so they can take the appropriate measures. The SPP RTO would assess if capacity or reserves would become insufficient due to the unavailable generation. If so, the SPP RTO would declare either an Energy Emergency Alert or Other Extreme Contingency and post as needed on the Reliability Coordinator Information System. The SPP RTO does not conduct operations planning studies to evaluate extreme hot weather conditions; capacity margin criteria are intended to address load forecast uncertainty.

Significant deliverability problems due to transmission limitations are not expected, assuming all projected projects are completed as scheduled. The SPP RTO will continue to closely monitor the issue of deliverability through the Flowgate assessment analysis[145], and will address any reliability constraints. This analysis validates the list of flowgates the SPP RTO monitors on a short-term basis, using scenario models developed by SPP RTO staff. These scenario models reflect all the potential transactions in various directions that are requested on the SPP RTO system. The results of this study are reviewed and approved by SPP's Transmission Working Group prior to summer and winter of each study year.

The SPP RTO monitors potential fuel supply limitations by consulting with its generation-owning and generation-controlling members at the beginning of each year. There are no known infrastructure issues which could impact deliverability, as the SPP Region is blanketed by major pipelines and railroads to provide an adequate fuel supply. Coal–fired and natural gas power plants, which make up approximately 48 percent and 44 percent of total generation respectively, are required by SPP RTO Criteria to keep sufficient quantities of standby fuel in case of deliverability issues. Because hydro capacity is a small fraction of capacity for the Region, run–of–river hydro issues brought about by extreme weather are not expected to be critical.

[145] See sections 4.1 and 4.2 of the SPP Criteria, which are in the Governing Documents folder of the SPP.org *Documents and Filings* library.

Energy-only resources, uncommitted resources, and transmission–limited resources are not used in calculating net capacity margin. The EIA–411 data does not include the 4,546 MW of uncommitted resources located within the SPP RTO footprint. These are reflected in the total potential resources capacity or reserve margin, which is considerably greater than the net capacity margin. The SPP RTO has plans to assess the highest short circuit levels that have been forecasted on its 230 kV+ transmission system; short circuit model development will begin in 2011. No reliability impacts have been addressed due to aging infrastructure or economic conditions, and at this time the SPP RTO does not have any guideline for on-site, spare-generator step-up and auto transformers.

The SPP RTO anticipates a significant amount of wind capacity to be added in the western part of the SPP footprint. Although these are predominantly energy-only resources and only a small portion of this capacity (according to SPP Criteria 12.3.5.g) will be counted as certain based on the historical trend, it would be sufficient to meet SPP's capacity or reserve margin requirement. No major unit retirements are planned within the next ten years.

States in the SPP RE footprint that have a Renewable Portfolio Standard are Oklahoma, Kansas, Missouri, New Mexico, and Texas. The impact of these portfolio standards was included in the Wind Integration Task Force and Priority Projects analysis.

Demand Response programs in the SPP RTO footprint are voluntary and because the amount is so miniscule it is not included in the planning process.

There are no known unit retirements during the assessment timeframe which will impact reliability in the SPP RTO footprint. The SPP RTO has an under-voltage load-shedding program in western Arkansas within the AEP-West footprint. This program targets about 180 MW of load shed during the peak summer conditions to protect the bulk power system against under-voltage events.

The SPP RTO has some temporary Special Protection Systems that are approved to be in place from 18 months to 5 years based on the reliability need. All Special Protection System requests are approved by the SPP's System Protection and Control Working Group. The SPP RTO does not have any special protection systems or remedial actions schemes to be to be installed in place of planned bulk power transmission facilities.

The SPP RTO develops an annual SPP Transmission Expansion Plan (STEP) that includes a group of projects to address Regional reliability needs for the next 10 years (2010 through 2019). The 2009 STEP was approved by the SPP Board of Directors in January 2010.[146] In addition to the STEP, and as a part of compliance assessment process, the SPP RTO also performs a dynamic stability analysis. The dynamic study completed for 2010 operating conditions did not indicate any dynamic stability issues for the SPP RTO Region. The SPP RTO also performs an annual review of reactive reserve requirements for load

[146] Download the 2009 STEP from the Engineering and Planning section of SPP.org

pockets within the Region. The SPP RTO does not have specific criteria for maintaining minimum dynamic reactive requirement or transient voltage dip criteria. However, according to the reactive requirement study scope, which was completed as a STEP process in 2009, each load pocket or constrained area was studied to verify that sufficient reactive reserves are available to cover the loss of the largest unit. The annual STEP process did not indicate limited dynamic and static reactive power areas on the bulk power system.

In October 2009, the SPP Board of Directors approved a new Integrated Transmission Planning (ITP) process that will determine what transmission is needed to maintain electric reliability and provide near- and long-term economic benefits to the SPP RE Region. Successful implementation of the ITP will result in a list of transmission expansion projects and completion dates that facilitate the creation of a reliable, robust, flexible, and cost-effective transmission network that improves access to the SPP RE Region's diverse resources, including its vast potential for renewable energy. The ITP is an iterative three-year process that includes 20-Year, 10-Year, and Near-Term Assessments.

Principles of the ITP:

- Focus on Regional needs, while integrating local needs
- Plan will be updated every 3 years
- Goal is to build a robust grid to meet near- and long-term needs
- Will result in comprehensive list of needed projects for SPP Region over next 20 years
- Plan the transmission backbone to connect known load centers to known or expected larger generation sites
- EHV transmission backbone should connect transmission between SPP's west and east Regions and strengthen existing ties to the Eastern Interconnection, with options for interconnecting to the Western grid
- Planning horizons will be 4, 10, and 20 years
- Will position SPP to proactively prepare and quickly respond to national priorities that may require additional consideration

The SPP RTO is developing a transmission portfolio for a 20-year planning horizon. The results of this analysis are expected by the end of 2010. The SPP RTO conducted a Power-Voltage analysis study for the nine potential load pockets within the SPP RTO footprint based on a 2014 summer peak load condition. SPP RTO staff will coordinate any potential reactive reserve issues and associated mitigation plans during its annual reliability assessment effort.

As a part of the interregional transmission transfer capability study, the SPP RE participates in the Eastern Interconnection Reliability Assessment Group seasonal study group (comprised of MRO, RFC, SERC West, and SPP), which produces an upcoming summer, winter, and long term summer operating condition transfer limitation forecast. Simultaneous transfers are also performed as part of this study. The results of the recently completed studies did not indicate any reliability issues for the SPP area.

As a Planning Authority, the SPP RE conducts reliability assessments to comply with NERC TPL standards:

- TPL-001 – The SPP Model Development Working Group (MDWG) ensures that all base case violations are addressed during Base Case development.

* TPL-002 - Using the SPP MDWG Models, Near and Long Term Analysis for N-1 contingencies are performed by SPP staff.
* TPL-003 - SPP staff performs automatic N-2 contingencies along with selected N-2 contingencies submitted by SPP members.
* TPL-004 - SPP periodically conducts reactive reserve and stability studies that address the key requirement in this standard. This standard covers the requirements of the SPP Region's planning process concerning selected catastrophic events.

Based on these studies, the SPP RE does not anticipate any near-term or long-term reliability issues that have not addressed by mitigation plans or with local operating guides. In March 2010, SPP RE member Oklahoma Gas and Electric (OG&E) installed approximately 42,000 smart meters on customer homes in Norman, Oklahoma, along with the information delivery infrastructure to carry the information to and from the customers and OG&E. An estimated 3,000 Norman customers will be asked to participate in a study in the summer of 2010 and 2011 using the in-home devices and/or Internet portals as a means to get electricity pricing and usage information. There are no known project slow-downs, deferrals, cancellations, or other issues at this time that will impact the reliability of the SPP RTO footprint.

Region Description

The Southwest Power Pool, Inc. Regional Transmission Organization (SPP RTO) Region covers a geographic area of 370,000 square miles and has members in nine[147] states: Arkansas, Kansas, Louisiana, Missouri, Mississippi, Nebraska, New Mexico, Oklahoma, and Texas. SPP's footprint includes 29 Balancing Authorities and over 50,000 miles of transmission lines. SPP typically experiences peak demand in the summer months.

SPP has 58 members that serve over 5 million customers. SPP's membership consists of 14 investor–owned utilities, 11 generation and transmission cooperatives, 10 power marketers, 9 municipal systems, 7 independent power producers, 4 state authorities, and 3 independent transmission companies. SPP was a founding member of the North American Electric Reliability Corporation in 1968, and was designated by the Federal Energy Regulatory Commission as an RTO in 2004 and a Regional Entity (RE) in 2007. As an RTO, SPP ensures reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. The SPP RE oversees compliance enforcement and reliability standards development. Additional information can be found at www.SPP.org.

[147] The SPP RE footprint does not include Nebraska

Northeast Power Coordinating Council, Inc. (NPCC)

Executive Summary

For the period 2010 through 2019, all subregions of NPCC project adequate planning margins, and the transmission system is expected to perform adequately. The Northeast Power Coordinating Council, Inc. has in place a comprehensive resource assessment program directed through Appendix D of the NPCC Regional Reliability Reference Directory #1, "Design and Operation of the Bulk Power System."[148] This document charges the NPCC Task Force on Coordination of Planning (TFCP) to assess periodic reviews of resource adequacy for the five NPCC Areas, or subregions. In assessing each review, the TFCP will ensure that the proposed resources of each NPCC Area will comply with Section 5.2 of NPCC Directory 1 which defines the criterion for resource adequacy for each Area as follows:

> "Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion 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. All of the NPCC subregions meet the NPCC adequacy criterion of disconnecting firm load due to resource deficiencies no more than 0.1 day per year on average."

All five of the NPCC subregions meet the planning requirement of Directory 1 for the ten-year study period.

With the impact of the economic downturn still being observed in the near-term load projections, together with the continuing expansion of Energy Efficiency programs, the projected growth rates over the ten-year study period are reduced or little changed from those seen in 2009:

Table NPCC-1: Average Annual Demand Growth Projection in NPCC

Subregion	2009	2010
Maritimes	0.90%	-0.50%
New England	1.20%	1.40%
New York	0.65%	0.64%
Ontario	-0.90%	-0.30%
Québec	1.30%	1.10%

[148] http://www.npcc.org/documents/regStandards/Directories.aspx

Enhancements to the transmission system are seen throughout NPCC in the ten-year study period, with the following key projects either being considered or in various stages of the planning process.

- The Maritimes is planning the Coleson Cove to Salisbury 345 kV circuit, still in the Conceptual stage.
- In New England, major plans include the Maine Power Reliability Program, the New England East-West Solution and the Vermont Southern Loop Project.
- The 345 kV Sprainbrook to Sherman Creek cable is currently being planned for the Con Edison system in New York.
- Ontario is planning to add additional outlets to the Bruce generating facility, the Bruce to Milton double circuit 500 kV project.
- Hydro-Québec TransÉnergie will reinforce the Chénier station permitting full used of the Ontario-Québec HVdc interconnection; additionally, the Chamouchouane to Boût-de-l'Île 735 kV circuit is planned to reinforce the Montréal load area. A 1,200 MW HVdc tie between New Hampshire and Hydro-Québec TransÉnergie is also in the planning stages.

Introduction

Recognizing their diversity, the adequacy of NPCC is measured by assessing the five subregions, or Areas, of NPCC: 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 Maritimes Area and Québec are predominantly winter peaking systems. The Ontario, the New York and the New England Areas are summer peaking systems. Consequently, the mix of winter and summer peaking areas would make a NPCC-wide comparison of year to year peaks misleading. Comparisons for the individual subregions follow. The expected growth, together with the overall reliability assessment of the projected transmission and resources, follows individually for the Maritimes Area, New England, New York, Ontario and Québec.

Region Description

NPCC is a New York State not-for-profit membership corporation, the goal of which is to promote and enhance the reliable and efficient operation of the international, interconnected bulk power system in northeastern North America:

- *through the development of Regional reliability standards and compliance assessment and enforcement of continent-wide and Regional reliability standards, coordination of system planning, design and operations, and assessment of reliability; and*
- *through the establishment of Regionally-specific criteria, and monitoring and enforcement of compliance with such criteria.*

Geographically, the portion of NPCC within the United States includes the six New England states and the state of New York. The Canadian portion of NPCC includes the provinces of New Brunswick, Nova Scotia, Ontario and Québec. Approximately 45% of the net energy for load generated in NPCC is within the United States, and approximately 55% of the NPCC net energy for load is generated within Canada.

Approximately 70% of the total Canadian load is within the NPCC Region. Geographically, the surface area of NPCC covers about 1.2 million square miles, and it is populated by more than 55 million people.

General Membership in NPCC is voluntary and is open to any person or entity, including any entity participating in the Registered Ballot Body of NERC, that has an interest in the reliable operation of the Northeastern North American bulk power system. Full Membership shall be available to entities which are General Members that also participate in electricity markets in the international, interconnected bulk power system in Northeastern North America. The Full Members of NPCC include independent system operators (ISO), Regional transmission organizations (RTOs), Transcos and other organizations or entities that perform the Balancing Authority function operating in Northeastern North America. The current membership in NPCC exceeds fifty entities.

Among the Areas (subregions) of NPCC, Québec and the Maritimes are predominately winter peaking Areas; Ontario, New York and New England are summer peaking systems. (http://www.npcc.org/).

MARITIMES SUBREGION

EXECUTIVE SUMMARY

The footprint of the Maritimes Area is comprised of the provinces of New Brunswick (served by the New Brunswick System Operator - NBSO), Nova Scotia (served by Nova Scotia Power Inc. - NSPI), Prince Edward Island - PEI (served by the Maritime Electric Company Ltd. - MECL) and the Northern Maine Independent System Administrator, Inc (NMISA). NMISA serves approximately 40,000 customers in northern Maine and is radially connected to the New Brunswick power system. The Maritimes Area is a winter peaking Region.

Forecast peak demand for the Maritimes Area in 2010/11 is 5,655 MW. Forecast average annual growth rate is negative at -0.5%, and is mostly due to higher demand side management (DSM) projections.

Existing capacity resources for 2010/11 total 7,338 MW, including 504 MW of wind generation. Due in part to the projection of a negative total load growth rate, there is no future plans to add more conventional generation capacity in the Maritimes Area within the next 10 years. However, wind generation is forecast to grow by 414 MW by 2019/20 driven by Regional renewable energy targets. For each year of the forecast, the reserve margin of the Maritimes Area exceeds 34% and thus meets the 20% reserve margin criterion used for planning purposes.

The only new bulk transmission forecast in this review period is a Conceptual project in New Brunswick to build a parallel circuit to the existing 103 miles of 345 kV transmission between Coleson Cove and Salisbury. This project is under study for 2016.

There are no significant generating unit outages, transmission additions or temporary operating measures that are anticipated to impact the reliability of the Maritimes during the next ten years.

DEMAND

The 2010/11 peak demand forecast, representing the summation of the forecasts of each Maritimes Area jurisdiction, is 5,655 MW. This is 175 MW higher than last year. The forecast average annual peak demand growth rate is -0.5% over the next 10 years, and this is lower than the 0.9% growth rate forecasted last year. Contributing significantly to this lower growth rate were higher demand side management (DSM) projections from Nova Scotia Power (NSPI) as noted in the NSPI 2009 Integrated resource Plan Update Report.[149]

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.

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[149] http://www.nspower.ca/site-nsp/media/nspower/2009%20IRP%20UPDATE%20-%20FINAL%20REPORT%20COMBINED%20REDACTED.pdf.

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 use of electrical energy.

The NSPI load forecast for Nova Scotia is based on the 10-year average temperatures measured in the Halifax area of the province, 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 MECL load forecast for 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.

All jurisdictions in the Maritimes Area are winter peaking due to high electric heating load. Long term resource evaluations are based on a 20% reserve margin above the forecast firm winter peak load.

Current and projected Energy Efficiency are either incorporated directly into the load forecast (New Brunswick, PEI, and Northern Maine), or reported separately (Nova Scotia). The reported Energy Efficiency for 2011/12 is 101 MW, growing to 551 MW in 2019/20.

Nova Scotia Power Inc.'s Energy Efficiency programs are spread across various customer sectors - residential, commercial and industrial. They include programs for lighting, heating/cooling, refrigeration, water heating, motors and compressors. NSPI has developed an updated Demand Side Management (DSM) plan, which is presently before the Regulator. DSM is a relatively new initiative for the Utility and the program includes reporting mechanisms (independent evaluation by NSPI's Evaluation Consultant, and subsequent verification by the Regulator's Verification Consultant) to assess the demand and energy benefits particularly during the ramp-up period in the next few years.

One of the Demand Response programs currently used in the Maritimes Area is interruptible demand. For 2010/11, the interruptible demand forecast for the peak month is 385 MW, which represents 7% of the peak demand forecast. In Nova Scotia, NSPI's Demand Response programs are primarily rate design-driven and along with interruptible pricing for large industrials, include time of day pricing for residential customers with electric thermal storage home heating equipment, and the Extra Large Industrial Interruptible Two Part Real Time Pricing rate for NSPI's two largest customers. Interruptible demand is reported separately; the other programs are incorporated directly into the load forecast.

While demand side management resources are considered for meeting Regional targets for greenhouse gas reductions, they are not currently counted towards Regional renewable portfolio standards.

In its comprehensive reviews of resource adequacy, the Maritimes Area uses a load forecast uncertainty representing the historical standard deviation of load forecast errors based upon the four-year lead time required to add new resources.

Generation

The Maritimes Area capacity resources in 2010/11, with wind capacity in brackets, are:

Table NPCC-2: Maritimes Capacity

	2010-2011	2019-2020
Existing Capacity	7,338 MW (504 MW)[150]	7,338 MW (504 MW)
Certain	7,257 MW (504 MW)	7,257 MW (504 MW)
Other	0 MW (0 MW)	0 MW (0 MW)
Inoperable	82 MW (0 MW)	82 MW (0 MW)
Future-Planned	209 MW (209 MW)	414 MW (414 MW)
Future Conceptual	0 MW (0 MW)	0 MW (0 MW)

Wind project capacity for the Maritimes is modeled based upon results from the September 2005 NBSO report "Maritimes Wind Integration Study." [151] This report showed that the effective capacity from wind projects, and their contribution to Loss of Load Expectation (LOLE) was equal to or better than their seasonal capacity factors. The coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects versus that of a summer peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production.

In Nova Scotia, the capacity contribution of wind projects during the peak is based on a three year rolling average of the winter peak period actual capacity factor (combined with the annual forecasted capacity factor, if in service less than three years). This is based on an agreed formula between the Renewable Energy Industry Association of Nova Scotia and NSPI.

The Biomass capacity values are 109 MW of Existing-Certain in both 2010/11 and 2019/20.

There is no Conceptual capacity resources expected to come on-line during the study period.

[150] The number in brackets () represents wind capacity

[151] http://www.nbso.ca/Public/_private/2005%20Maritime%20Wind%20Integration%20Study%20_Final.pdf

With relatively flat and even slightly negative load growth, there are no current plans for additional MW of conventional generation within the Maritimes Area. Future-Planned capacity for this study period consists entirely of new wind capacity driven by Regional renewable energy targets.

Capacity Transactions on Peak

The Maritimes Area does not forecast any capacity imports from other Regions during the next 10 years.

For the period 2010 through October 2011, there is a firm capacity sale of 200 MW from the Maritimes to Hydro-Québec. This sale is tied to two 100 MW oil combustion turbines at Millbank, NB and is backed up by a transmission reservation.

Transmission

In terms of Conceptual transmission, New Brunswick is studying a 345 kV transmission line project between Coleson Cove and Salisbury. This line would be 103 miles in length, and is targeted for 2016. As this project is still Conceptual, there are no reliability impacts in not meeting its proposed in-service date.

There are no transmission constraints in the Maritimes Area affecting reliability.

No other significant substation equipment additions planned for the Maritimes Area within the next 10 years.

Operational Issues

There are no significant generating unit outages, transmission additions or temporary operating measures that are anticipated to impact the reliability of the Maritimes Area during the next ten years.

In the 2007 Maritimes Comprehensive Review of Resource Adequacy [152] scenarios of high load growth and zero wind availability were studied, with the result that the Maritimes Area was still able to meet its 20% reserve criterion in all cases with no more than 35 MW of necessary interconnection support. This level of interconnection support represents only 2% of the Maritimes Area tie benefits capability.

There are no current environmental or regulatory restrictions that could potentially impact the reliability of the Maritimes Area.

Plans are underway for the individual jurisdictions within the Maritimes Area to coordinate the sharing of wind data and possibly wind forecasting information and services.

In Nova Scotia, provincial legislation is in place to meet renewable supply targets in 2010 and 2013 (including variable/intermittent resources). The 2008 Wind Integration Study[153] commissioned by the Nova Scotia Department of Energy found that for the 2013 target, more detailed impact studies are required to fully understand the cost and technical implications related to possible transmission

[152] http://www.npcc.org/documents/reviews/Resource.aspx

[153] http://www.gov.ns.ca/energy/resources/EM/Wind/NS-Wind-Integration-Study-FINAL.pdf

upgrades and new operational demands on existing infrastructure. Future study will be needed to fully understand the cost and stability issues of increasing wind supply beyond these levels.

There are no operational changes or concerns resulting from distributed resource integration in the Maritimes Area other than in Nova Scotia.

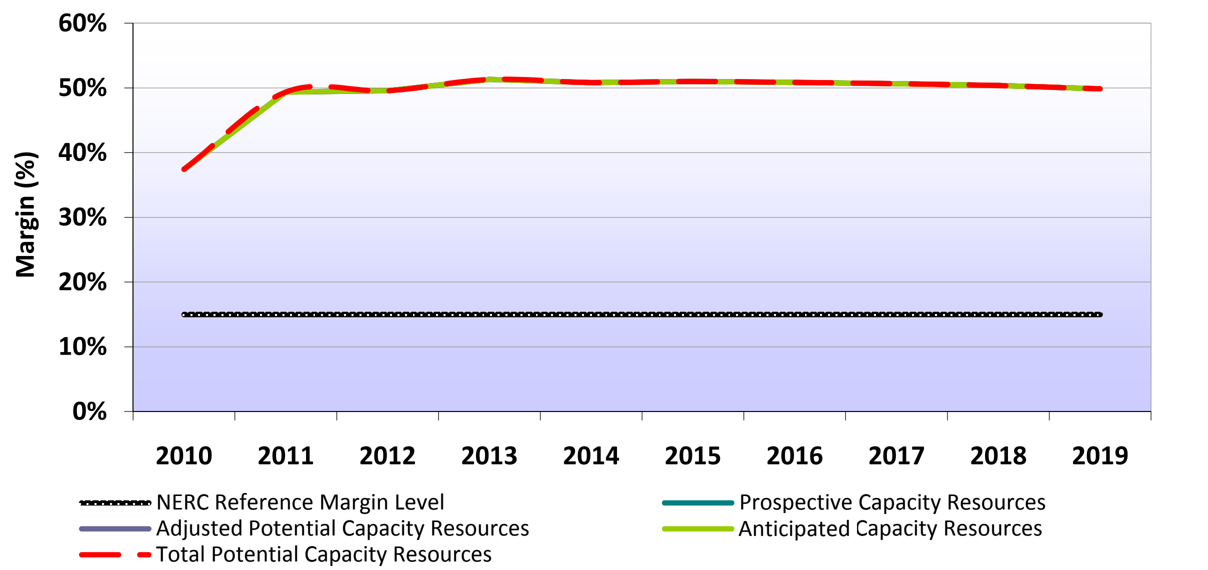
In Nova Scotia, as increased amounts of renewable generation are connected to the distribution system, further study will be required to fully understand the cost and technical implications related to possible transmission system upgrades and new operational demands on existing infrastructure.

No reliability issues are anticipated from Demand Response resources for the Maritimes Area, which consist mainly of interruptible customers totaling 7% of peak demand in 2010/11.

Reliability Assessment Analysis

For each year of the forecast, the reserve margin of the Maritimes Area exceeds 34%. The Maritimes uses a reserve criterion of 20% for planning purposes and it was shown in the 2007 Maritimes Comprehensive Review of Resource Adequacy that adherence to this criterion complies with the NPCC reliability criterion.

Figure NPCC-1: Winter Peak Reserve Margin Projections



The Maritimes conducts resource adequacy studies to identify the resources needed to meet the NPCC resource adequacy criterion of less than 0.1 day per year of Loss of Load Expectation (LOLE).

In its 2007 Maritimes Comprehensive Review of Resource Adequacy it was shown that the NPCC reliability criterion of less than 0.1 day of firm load disconnections per year is not exceeded by the Maritimes Area for all years in the 2008-12 study period, and varies between 0.001 to 0.086 day/yr for the base load forecast with load forecast uncertainty.

The Maritimes Area requires no support from its interconnections to meet the NPCC reliability criterion for all years of the 2008-12 study periods. The Maritimes Area is also shown to adhere to its own 20% reserve planning criterion in all years for the base load forecast, with reserve levels varying between 22% and 40%.

The Maritimes Area has sufficient resources to meet its 20% reserve requirement for each of the 10 years of this assessment. No additional internal or external resources are required.

The Maritimes Area participates in a Regional reserve sharing program with New England, New York, and Ontario for 100 MW of 10-minute reserve. This reserve is counted as 25% spinning and 75% supplemental.

Both short-term and long term capacity requirements are the same in the Maritimes Area.

In its 2007 Maritimes Comprehensive Review of Resource Adequacy, the scenarios of high load growth and zero wind availability were studied, with the result that the Maritimes Area was still able to meet its 20% reserve criterion in all cases with no more than 35 MW of necessary interconnection support. This level of interconnection support represents only 2.1% of the Maritimes Area tie benefits capability.

Wind project capacity for the Maritimes is modeled based upon results from the Sept. 21, 2005 NBSO report “Maritimes Wind Integration Study”. This report showed that the effective capacity from wind projects, and their contribution to Loss of Load Expectation (LOLE) was equal to or better than their seasonal capacity factors. The coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects versus a summer peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production.

In Nova Scotia, the capacity contribution of wind projects during the peak is based on a three year rolling average of the winter peak period actual capacity factor (combined with the annual forecasted capacity factor, if in service less than three years). This is based on an agreed formula between the Renewable Energy Industry Association of Nova Scotia and NSPI.

Wind capacity required to meet Maritimes Area Renewable Portfolio Standard (RPS) mandates have been included within Future Capacity.

All generation projects connecting to the transmission grid, including wind, must undergo a System Impact Study (SIS) and satisfy all connection requirements determined by the SIS and local grid code. Wind projects are required to transmit atmospheric data (wind speed, wind direction, temperature) to the local System Operator for wind forecasting needs.

The Demand Response in the Maritimes Area consists primary of interruptible customer load equivalent to 7% of peak load for 2010/11. The performance of these customers is metered in real-time to ensure compliance with operator instructions.

There are no unit retirements during the period of this assessment that significantly impact the reliability of the Maritimes Area.

At this time, there are no plans to install more Under Voltage Load Sharing (UVLS) in the Maritimes Area. Collectively, UVLS in New Brunswick can shed up to 25% of load. There are no plans for additional Special Protection Systems (SPS) schemes in the Maritimes Area in this assessment.

The Maritimes Area addresses the loss of generation through its operating reserve requirements, and due to its diverse fuel mix and fuel storage capability, there are no long-term fuel disruptions anticipated.

NPCC has established a Reliability Assessment Program (NRAP) to bring together work done by the Council, its member systems and Areas relevant to the assessment of bulk power system reliability. As part of the NRAP, the Task Force on System Studies (TFSS) is charged on an ongoing basis with conducting periodic reviews of the reliability of the planned bulk power transmission system of each Area of NPCC and the transmission interconnections to other Areas. The purpose of these reviews is to determine whether each NPCC Area's planned bulk power transmission system is in conformance with the NPCC Regional Reference Directory #1 "Design and Operation of the Bulk Power System". Since it is NPCC's intention that the *Basic Criteria* be consistent with the NERC *Planning Standards*, conformance with the NPCC *Basic Criteria* assures consistency with the NERC *Planning Standards*.

The Transmission Review for 2009 is an Intermediate level, covering the year of 2014. The results of this study concluded that the bulk power system for the Maritimes Area remains in conformance with Directory #1.There are no reactive power-limited areas on the bulk power system for the Maritimes Area. Voltages on the system are operated within the limit of 0.95 per unit to 1.05 per unit.

There are no new FACTS or "smart grid" devices planned for the Maritimes Area bulk power system during the assessment period, and no specific new projects that impact reliability in the Maritimes Area over the next 10 years

Region Description

Table NPCC-2: Maritimes Description

Jurisdiction	System Operator	Peak Season	Square Miles	Population
New Brunswick	NBSO	Winter	28,000	750,000
Nova Scotia	NS Power	Winter	21,000	940,000
Prince Edward Island	Maritime Electric	Winter	2,200	140,000
Northern Maine	Northern Maine ISA	Winter	3,600	90,000

NEW ENGLAND SUBREGION

EXECUTIVE SUMMARY

For this *2010 Long-Term Reliability Assessment*, ISO New England Inc. (ISO-NE) forecasts no major reliability issues with respect to fuel supply, availability of both supply or demand-side resources, or the capability of the Regional transmission system to serve the projected seasonal peak demands and energy requirements of the six-state New England Region.

New England, a subregion of NPCC, is a summer peaking system. The 2009 summer actual peak demand was 25,100 MW which was 2,775 lower than the last year's *2009 Long-Term Reliability Assessment* projection for the 2009 summer peak demand of 27,875 MW. A non-typical, rainy summer season in 2009 in New England produced very few peak demand days. The Total Internal Demand projected for the 2010 summer is 27,190 MW and for the 2019 summer is 30,730 MW. This year's forecast of the ten-year (2010-2019) 50/50 summer peak demand compound annual growth rate (CAGR) is 1.4 percent. For the entire assessment period, the Net Internal Demand equals the Total Internal Demand.

For the 2010 summer, the Existing Capacity totals 32,567 MW which is 1,422 MW lower than last year's value of 33,989 MW. For the 2010 summer, the Existing-Certain capacity totals 32,251 MW which is 1,166 MW lower than last year's value of 33,417 MW. Approximately 3,010 MW of Future Capacity Additions are projected to be commercialized by the 2019 summer. Approximately one third (1,000 MW) of these overall capacity additions are new Demand Response Expected On-Peak and no major retirements of capacity is forecast through the end of the assessment period.

New England does not have a target reserve margin requirement. The NERC reference reserve margin for a thermal power system like New England is 15 percent. New England's 2010 summer reserve margin is 19.7 percent, which is 4.7 percent above the NERC reference reserve margin. The summer reserve margin for Existing-Certain, and Net Firm Transaction ranges from a high of 24.0 percent in 2011 to a low of 4.6 percent in 2019. Based on the forecast of the Region's Installed Capacity Requirement (ICR) for 2019, it is estimated that New England's actual 2019 summer reserve margin would be no lower than 13.3 percent.

Transmission projects are developed to serve the entire New England Region reliably and are fully coordinated with other Regions. The following are significant additions projected to be placed in-service through the end of the assessment period:

1. The Maine Power Reliability Program (MPRP) establishes an additional 345 kV path through the state of Maine, beginning at Orrington. The new path continues south to Surowiec and ultimately ends at a new switching station at Three Rivers, near the Maine-New Hampshire border.
2. The New England East–West Solution (NEEWS) series of projects had been identified to improve system reliability. These projects include the addition of significant 345 kV transmission in Massachusetts, Rhode Island, and Connecticut. The continued need for all of the NEEWS projects is currently under review.
3. The Vermont Southern Loop Project installs a 51-mile 345 kV line between Vermont Yankee and Coolidge along with two 345/115 kV autotransformers at Newfane and Vernon.

Over the course of the assessment period, the two most significant issues facing the northern New England area have been to maintain the general performance of the long 345 kV corridors, particularly through Maine, and to maintain the reliability of supply to meet demand. Studies show that the region could potentially face thermal, voltage performance, and stability concerns without the addition of system improvements identified by the Region. The area is also reliant on several Special Protection Systems (SPS) that have increasing exposure to incorrect or undesired operation. System upgrades, which are either in progress or have been recently completed, provide required relief for these areas.

Although recent improvements have been made, longer-term studies of the southern New England system indicate possible future thermal, low-voltage, high-voltage, and short-circuit concerns under certain system conditions. The most significant concerns involve maintaining the reliability of supply to serve demand and developing the transmission infrastructure to integrate generation throughout this area. Similar to northern New England, many system upgrades, which are either in progress or have been recently completed, will address these concerns.

This *2010 Long-Term Reliability Assessment* identifies three issues that could possibly impact future system reliability. These are:

1. A potentially large influx in the amount of new variable capacity resources namely wind generation.[154] Currently, New England has very little existing wind capacity (less than 200 MW of nameplate), but concerns exist over the resultant impacts from compliance with state Renewable Portfolio Standards (RPS), and the corresponding build-out of these new supply-side resources in the near-term.
2. The unknowns associated with two upcoming nuclear plant (1,281 MW in total) relicensing processes that are scheduled to occur within a two year time frame.[155]
3. The potential need to modify, refurbish or retire, both river and coastal, steam-generation power plants that currently use *"once-through"* cooling with *"closed-loop"* cooling systems.

The uncertainty and variability of new wind resources may pose operational challenges. The New England Wind Integration Study (NEWIS) is investigating the operational impacts of different penetration levels of wind resources. The study will also recommend changes in operating practices and procedures to accommodate a large-scale penetration of wind resources.

DEMAND

A continuation of the economic downturn has lowered this year's forecast for summer peak demand and energy use when compared to last year's forecast. This year's forecast of the ten-year (2010-2019) 50/50 summer peak demand compound annual growth rate (CAGR) is 1.4 percent which has slightly increased from last year's ten-year (2009-2018) CAGR forecast of 1.2 percent for summer peak demand.

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[154] Currently, ISO-NE has approximately 2,650 MW (total) of new onshore and offshore wind projects requesting study within its Generation Interconnection Queue.

[155] Within New England, approximately 1,281 MW of nuclear capacity has their current NRC Operating License expiring within a two-year timeframe and approximately 3,347 MW of nuclear capacity has their current NRC Operating License expiring within a fifteen-year timeframe.

However, this 2010 CAGR is somewhat misleading, as the demand level in the first year (2010) of the forecast is significantly lower due to the current economic downturn. This biases the overall compounded annual average growth rate in an upward fashion. The key factor leading to the lower summer peak demand forecast is that the economic downturn has significantly impacted the actual summer peak and energy demand within the New England Region, which results in approximately a one to two year delay in achieving the same demand levels that had been previously predicted.

This year's forecast of the ten-year winter peak demand CAGR is 0.5 percent which has increased slightly from last year's ten-year CAGR forecast of 0.4 percent for winter peak demand. The forecast for winter peak demand is slightly higher than last year's forecast by the end of the forecast period based on updated historical demands and economic and price of electricity forecasts. The winter peak is less weather sensitive than the summer peak, closely linked to residential demand (the convergence of darkness and dinner), and less affected by the recession.[156]

This year's forecast of the ten-year net annual energy CAGR is unchanged from last year's forecast of 0.9 percent. However, the overall forecast for net annual energy use is lower than last year's forecast due to the economic downturn.

ISO-NE's reference case demand forecast is the 50/50 forecast (50 percent chance of being exceeded), corresponding to a New England three-day weighted temperature-humidity index (WTHI) of 79.9, which is equivalent to a dry-bulb temperature of 90.2 degrees Fahrenheit and a dew point temperature of 70 degrees Fahrenheit. The reference case demand forecast is based on the most recent reference economic forecast, which reflects the economic conditions that "most likely" would occur.

ISO-NE develops an independent demand forecast for the Balancing Authority area as a whole and the six states within it. ISO-NE uses historical hourly demand data from individual member utilities, which is based upon Revenue Quality Metering (RQM), to develop historical demand data from which the Regional peak demand and energy forecasts are based upon.[157] From this historical data, ISO-NE develops a forecast of both state and monthly peak and energy demands. The peak demand forecast for the Region and the states can be considered a coincident peak demand forecast.

Demand side resources are considered capacity resources in New England's FCM. Under FCM, there are passive demand resources (non-dispatchable/Energy Efficiency) and active demand resources (dispatchable/interruptible). The active demand resources can be triggered by ISO-NE in real-time under ISO-NE Operating Procedure No. 4 – *Action during a Capacity Deficiency* (OP4) to help mitigate a capacity deficiency, or dispatched day-ahead to mitigate a projected capacity deficiency.

As part of the qualification process to participate in a Forward Capacity Auction (FCA), any new demand resource must submit detailed information about the project, including location, project description, estimated demand reduction values, and projected commercial operation dates along with a project

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[156] The winter peak is also somewhat dependent on electric heating demand, while the summer peak is directly-dependant on air conditioning demand. A much larger number of homes in New England have air conditioning versus electric heat.

[157] RQM is submitted to the ISO-NE Settlements Department.

completion schedule. In addition, new demand resources must submit a Measurement and Verification (M&V) Plan, which must be approved by ISO-NE. The project sponsor is required to submit certification that the project complies with their ISO-approved M&V Plan. ISO-NE has the right to audit the records, data, and actual installations to ensure that the Energy Efficiency projects are providing the load reduction as contracted. ISO-NE tracks the project against their submitted schedules, thereby taking a proactive role in monitoring the progress of these resources to ensure they are ready to reduce demand by the start of the applicable FCM commitment period.

The demand resources that have cleared into the FCM through the first three auctions are: 1,898 MW of demand resources (572 of passive and 1,326 of active) will be available by August 2010, 2,388 MW by August 2011 (784 passive, 1,554 active), 2,898 MW by August 2012 (1,073 passive, 1,825 active), which are then held constant through the 2019 summer.

In addition to reliability-based DR programs, ISO-NE administers a price-response DR program where demand voluntarily interrupts based on the price of energy. As of May 2010, there were approximately 65 MW enrolled in the price response program. These programs are not counted as capacity resources since their interruption is voluntary.

Although several types of Demand-Side Management resources can be used to satisfy state-mandated, renewable portfolio standards (RPS), ISO-NE does not require that information be submitted in order to participate in applicable demand-side markets.

ISO-NE addresses peak demand uncertainty in two ways:

1. Weather – Annual peak demand distribution forecasts are made based on 40 years of historical weather which includes the reference forecast (50 percent chance of being exceeded), and extreme forecast (10 percent chance of being exceeded);[158]
2. Economics – Alternative forecasts are made using high and low economic scenarios.

ISO-NE also reviews projected summer and winter conditions of the assessment period using the annual extreme, 90/10 peak demand based on the reference economic forecast.

GENERATION

As shown in Table NPCC-3, the companies within the New England subregion of NPCC expect to have the following aggregate capacity available on peak. Capacity in the categories of Existing (Certain, Other and Inoperable), Future (Planned and Other) and Conceptual are projected to serve demand during the ten-year assessment period.

[158] On an annual basis, the 50/50 reference peak has a 50 percent chance of being exceeded, and the 90/10 extreme peak has a 10 percent chance of being exceeded.

Table NPCC-3: New England Capacity Breakdown		
Capacity Type	**2010 (MW)**	**2019 (MW)**
Existing-Certain	32,251	32,251
Nuclear	4,612	4,612
Hydro/Pumped Storage	3,173	3,173
Coal	2,613	2,613
Oil/Gas/Dual Fuel	18,887	18,887
Other/Unknown	127	127
Solar	0	0
Biomass	914	914
Wind	26	26
Load Management Programs	1,898	1,898
Existing-Other	317	317
Existing-Inoperable	0	0
Future-Planned	0	2,806
Future-Other	224	204
Conceptual	0	7,638[159] / 1,528[160]
Wind	0	2,642
Solar	0	0
Hydro	0	38
Biomass	0	327

[159] Total Conceptual Capacity

[160] Total Conceptual capacity with the 20 percent Confidence Factor applied.

As of June 1, 2010, ISO-NE implemented its Forward Capacity Market (FCM) from which Regional capacity is procured in advance to satisfy Regional reliability requirements. June 1, 2010 marks the date by which Regional capacity that now has Capacity Supply Obligations (CSO) under the FCM is reported within this *2010 Long-Term Reliability Assessment* as Existing-Certain capacity and all remaining non-CSO capacity is reported as Existing-Other capacity.[161] Since ISO-NE has already procured the CSO for the 2012/2013 Capability Period, Regional capacity, through the time period 2010 through 2013, is identified within one of these two categories, depending on their CSOs. Beginning with the 2014 summer, those prior CSOs are then held constant throughout the assessment period.

For August 2010, ISO-NE reports 32,567 MW of Existing Capacity, which includes 32,251 MW of Existing-Certain capacity, 317 MW of Existing-Other capacity, and 0 MW of Existing-Inoperable capacity.

For August 2010, ISO-NE reports 111 MW of nameplate wind capacity, which includes 26 MW of Existing-Certain wind capacity expected on-peak along with an 85 MW on-peak derate of Existing-Other wind capacity. By August 2019, ISO-NE reports an additional 294 MW of Future, Planned nameplate wind capacity with 67 MW expected on-peak along with a 227 MW on-peak derating. Planned wind capacity is rated different from its nameplate capability due to Market Rules for rating intermittent supply-side resources, which also takes into account the site-specific wind characteristics of those projects. In 2019, Conceptual wind capacity is 2,642 MW, which is based on nameplate ratings, and has target in-service dates of 2011 through 2016.

For August 2010, ISO-NE reports 0 MW of Conceptual capacity on the system which also included 0 MW of wind, solar or biomass resources. However, by August of 2019, ISO-NE reports an additional 7,638 MW of Conceptual capacity potentially on the system. This amount also includes 2,642 MW of Conceptual on-peak wind capacity, 0 MW of Conceptual solar capacity, 38 MW of Conceptual on-peak, hydro-electric capacity, and 327 MW of Conceptual on-peak biomass capacity. The on-peak capacity ratings of variable or intermittent resources are determined from the Market Rules pertaining to qualification determination of capacity within the FCM.

ISO-NE's Reserve Margin calculations include Future Capacity Additions that are projected to begin commercial operation by the end of each year. If the new project's in-service date is prior to August 1st of that year that capacity is included within the Future, Planned capacity for the summer of the year, otherwise it is included within the Future, Planned capacity for the winter of the following year. This information is based on either the date specified in a signed Interconnection Agreement (IA) or discussions with ISO-NE indicating that the project is nearing completion and is preparing to become an ISO generator asset. Also included in the Future Capacity Additions are new projects that have

[161] Derates for all resources other than wind and hydro are based on the difference between their CSO and their Qualified Capacity, or the maximum amount with which they could participate in the Forward Capacity Auctions. Qualified Capacity is similar to the generators' Seasonal Claimed Capability. For wind and hydro, the derates are the difference between the CSO (within Existing-Certain) and nameplate capacity. These derates, along with ISO New England capacity that did not participate in the Forward Capacity Market, are included in the Existing-Other category.

contractual obligations within the ISO-NE FCM for the years 2010-2013. Conceptual capacity is subsequently identified as all the capacity remaining within the ISO-NE Generation Interconnection Queue that has not been designated as Future, Planned capacity, through the selection process identified above.

ISO-NE has a total of 8,809 MW of projects categorized as either Future, Planned capacity or Conceptual capacity within its Generator Interconnection Queue, with in-service dates ranging from 2011 to 2016.[162] Although some projects that reside within the ISO-NE Generator Interconnection Queue have declared in-service dates of 2010 or 2011, some of those projects have not demonstrated viable pre-commercial activities and have therefore been categorized as Conceptual capacity. The Queue projects were included in the Future, Planned category if they had an FCM obligation or were projected to be in service by 2010 summer. All other Queue projects were treated as Conceptual.

A 20 percent Confidence Factor has been applied to the amount of projected Conceptual capacity resources. This 20 percent Confidence Factor represents the amount of Conceptual capacity that may become commercialized within the Region, starting in the year 2011. This 20 percent Confidence Factor is held constant going forward in time. In the 2019 summer, the total amount of Conceptual capacity resources is 7,638 MW and applying the 20 percent Confidence Factor equates to approximately 1,528 MW.

ISO-NE currently addresses generation deliverability through a combination of transmission reliability and resource adequacy analyses. Detailed transmission reliability analyses of sub-areas of the New England bulk power system confirm that reliability requirements can be met with the existing combination of transmission and generation. Multi-area probabilistic analyses are conducted to verify that inter-sub-area constraints do not compromise resource adequacy. New capacity resources are subject to overlapping impact studies to ensure deliverability within the sub-area (load zone) in which they are seeking to interconnect. These load flow studies are part of the FCM's new capacity resource qualification process. The ongoing transmission planning efforts associated with the New England Regional System Plan (RSP) support compliance with the NERC Transmission Planning requirements and assure that the transmission system is planned to sufficiently integrate generation with demand.

Capacity Transactions On-Peak

As shown in Table NPCC-4, the companies within the New England subregion of NPCC expect to have the following aggregate firm capacity imports and exports during the ten-year assessment period.

Firm summer capacity imports amount to approximately 388 MW in 2010, 2,150 MW in 2011, 1,920 MW for 2012, and 334 MW in 2013 and 2014. The capacity imports for 2010 through 2013 reflect the results of the appropriate Forward Capacity Auctions (FCAs). The 2013 FCA results were assumed to remain in place in 2014. Since the FCA imports are based on one-year contracts, beginning in 2015 the imports reflect only known, long-term Installed Capacity (ICAP) contracts. Firm summer capacity imports are 284 MW in 2015, 112 MW in 2016, and then level off at 6 MW for the 2017, 2018, and 2019

[162] As of the April 1, 2010 ISO-NE Generation Interconnection Queue publication.

summers. If the imports that cleared in the 2013 summer do not clear in future FCM commitment periods, the lost capacity will be replaced by other supply or demand-side resources. There are no Expected or Provisional capacity imports projected for the assessment period.

Table NPCC-4: New England Purchases and Sales

Transaction Type	2010 Summer (MW)	2014 Summer (MW)	2019 Summer (MW)
Firm imports (external subregion)	388	334	6
Firm exports (external subregion)	100	100	100
Expected imports (external subregion)	0	0	0
Expected exports (external subregion)	0	0	0
Provisional imports (external subregion)	0	0	0
Provisional exports (external subregion)	0	0	0

The entire amount of ICAP imports are backed by firm contracts for generation and the imports under the FCM are import capacity resources with an obligation for the 2010-2013 commitment periods. Although there is no requirement for those imports to have firm transmission service, it is specified that deliverability of firm imports must meet New England delivery requirements and should be consistent with the deliverability requirements of internal generators. The market participant is free to choose the type of transmission service it wishes to use for the delivery of firm energy, but the market participant bears the associated risk of market penalties if it chooses to use non-firm transmission services. Import assumptions are not based on partial path reservations.

For the 2010 summer, ISO-NE reports a firm capacity sale to New York (Long Island) of 100 MW, anticipated to be delivered via the Cross-Sound Cable (CSC). This firm capacity sale is held constant through the assessment period. It should be noted that there is no firm transmission arrangement through the New England Pool Transmission Facilities (PTF) system associated with this contract. There are no Expected or Provisional capacity exports projected for the assessment period. Export assumptions are not based on partial path reservations.

TRANSMISSION

ISO-NE's Regional System Plans (RSPs) identify the Region's needed transmission improvements for this ten-year period. The current plan builds on the results of previous RSPs and other Regional activities. The transmission projects have been developed to coordinate major power transfers across the system, improve service to demand, and meet transfer requirements with neighboring balancing authority areas. Each RSP describes the transmission upgrades that are critical for maintaining the bulk power system. The New England Region currently has over 200 transmission projects and components in various stages of planning, construction, and implementation.

Presently there are no significant concerns over meeting target in-service dates. However, if the implementation of much needed projects is delayed, interim measures will be taken, such as issuing gap *Requests-for-Proposals* (RFPs) to install temporary generation in a specific area of the system.

Currently, there are no transmission constraints which prevent the system from being operated in a manner which ensures the reliability of the New England-wide system.

Significant transmission additions projected to be installed on the Regional bulk power system that will influence reliability are included in *Appendix III*. A new Static Var Compensator (SVC) was installed at the 115 kV Barnstable substation as part of the Short-Term Lower SEMA upgrades in the fall of 2009. Other additional significant substation equipment, including 345 kV shunt reactive devices, in the Region may be found on the ISO-NE project list.[163]

Operational Issues

There are no existing or potential systemic generating unit or transmission outages that are anticipated to impact reliability during the next ten years. The system will remain reliant on a number of Special Protection Systems (SPS) and local operating procedures until transmission solutions are placed in service in a number of areas within New England. A potentially large influx in the amount of new, intermittent capacity resources, namely wind generation, could commercialize in the near-term.[164] Nuclear plant relicensing and replacement of *once-through* cooling systems are probably the only open issues.[165,166]

If New England experiences extreme summer weather that results in 90/10 peak demands or greater, ISO-NE still should have enough operable capacity available to reliably manage the bulk power system. However, if supply-side outages diminish New England's operable capacity to serve these 90/10 peak demands, ISO-NE will need to invoke Operating Procedure No. 4 — *Action During a Capacity Deficiency*

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163 Located at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/

164 Currently, ISO-NE has approximately 2,650 MW of new wind (onshore and offshore) projects requesting study within its Generation Interconnection Queue.

165 Clean Water Act Section 316b (dealing with intake requirements) requires a significant reduction of the impacts of impingement and entrainment of aquatic organisms in existing power plants. The reduction measures must reflect the use of Best Available Technology (BAT). The BAT requirements are implemented when the existing National Pollution Discharge Elimination System (NPDES) permits for power plants expire and subsequently are renewed. Currently, EPA provides guidance on renewal on a permit-by-permit basis. On April 1, 2009 the U.S. Supreme Court delivered an opinion that benefit/cost analyses could be used in determining the BAT permit requirements. Without considering benefit/cost, existing generating plants potentially would need to retrofit cooling towers to meet these requirements. One New England plant's recent NPDES permit renewal requires cooling towers or alternatives with an equivalent performance. It also could affect system reliability through the reduction of plant capacity and, possibly, extended construction outages of key generating facilities. The ISO will monitor the EPA's follow up regarding the Supreme Court's decision on the permitting process and the use of benefit/cost to determine whether any reliability evaluation is needed regarding the potential for retrofitting existing plants with cooling towers.

166 Approximately 1,281 MW of nuclear capacity has their NRC Operating License expiring within two years. It is unknown at this time whether the owners of these nuclear assets will apply to the NRC for an extension to their current operating permits.

(OP4). OP4 is designed to provide additional generation and load relief needed to balance electric supply and demand while striving to maintain appropriate levels of operating reserves. Load relief available under OP4 includes relief from voltage reduction and emergency assistance from neighboring balancing authorities.[167]

During extremely hot summer days or combined with low hydrological conditions, there may be environmental restrictions on river-based or coastal generating units due to environmental constraints. Such conditions could result in temporary operable capacity reductions ranging from 100 to 500 MW. These reductions are reflected in ISO-NE's forced outage assumptions. ISO-NE monitors these situations and projects adequate resources to cover such environmental outages or reductions.

As of the 2010 summer, there is only 26 MW of Existing-Certain on-peak wind capacity on the New England system, so operational challenges from the integration of variable resources are negligible at this time. However, in the near-term, one emerging issue is the potential for a large influx of these new, intermittent wind resources to be commercialized within the Region. Concerns exist over the resultant impacts from compliance with state Renewable Portfolio Standards (RPS), and the potential build-out of these new supply-side resources. Because of this and other operational concerns, ISO-NE is finalizing a major wind integration study to identify the detailed operational issues of integrating large amounts of wind resources into the New England power grid. This wind study will also propose solutions to those problems.

Distributed generation must be integrated into the local electric company's distribution systems and it must comply with the interconnection standards applicable to such systems. This distributed generation is traditionally not a major concern for bulk power system operation, although relatively large DG projects can be studied by ISO-NE. ISO-NE does not anticipate any operational problems or reliability concerns resulting from the levels of distributed generation enrolled within the Demand Response programs.[168] The FCM qualification process requires additional information for projects that include the use of DG to ensure that they comply with the definition of DG within FCM. A 600 MW cap on real-time emergency generation (RTEG) within FCM was a limit that was negotiated during the development of the Market Rules for FCM and this amount is not expected to change within the near future.[169] In

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[167] It should be noted that within NPCC, there are power systems that are both summer and winter peaking. Since the New England system is summer peaking, surplus operable capacity should be available with the NPCC Canadian systems due to their winter peaking nature. This surplus operable capacity could be delivered to New England in the event OP4 is required. Routine discussions within NPCC identify whether surplus operable capacity is available on a on a daily, weekly or seasonal basis.

[168] Within New England, the capacity and load relief benefits from triggering distributed generation, Real-Time Emergency Generation (RTEG), is only attainable through the invocation of ISO-NE Operating Procedure No. 4 – *Action during a Capacity Deficiency* (OP4) – Action 6 of 11.

[169] RTEG is limited to 600 MW in the FCA per the Market Rule III.13.2.3.3.(f) Treatment of Real-Time Emergency Generation Resources: In determining when the FCA is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation (RTEG) resources shall be counted towards meeting the ICR (net of Hydro-Quebec Interconnection Capacity Credits (HQICCs)).

October 2009, 630 MW of RTEG cleared the third FCA for the 2012 - 2013 Capacity Commitment period. This amount will eventually be pro-rated down to the 600 MW RTEG limit for inclusion within ICR modeling.

As discussed earlier, 1,898 MW of demand-side capacity is currently enrolled in Demand Response programs for August 2010. With the start of the FCM in June 2010, Demand Response, Energy Efficiency, and distributed generation all will be treated as capacity resources, and demand resources will represent 5.8 percent of the representative capacity resources needed (*i.e.*, the Installed Capacity Requirement (ICR))[170] within the New England electric system in 2010.[171] There are currently no reliability concerns projected as a result of these amounts of Demand Response penetration into the system.

On a positive note, as a result of the U.S. DOE's 2009 Congestion Study, the DOE is dropping New England off its list of *"Congestion Areas of Concern,"* citing the Region's *"multi-faceted approach"* that has spurred investment in new supply-and demand-side resources, as well as planning and development of extensive transmission upgrades.[172]

Reliability Assessment Analysis

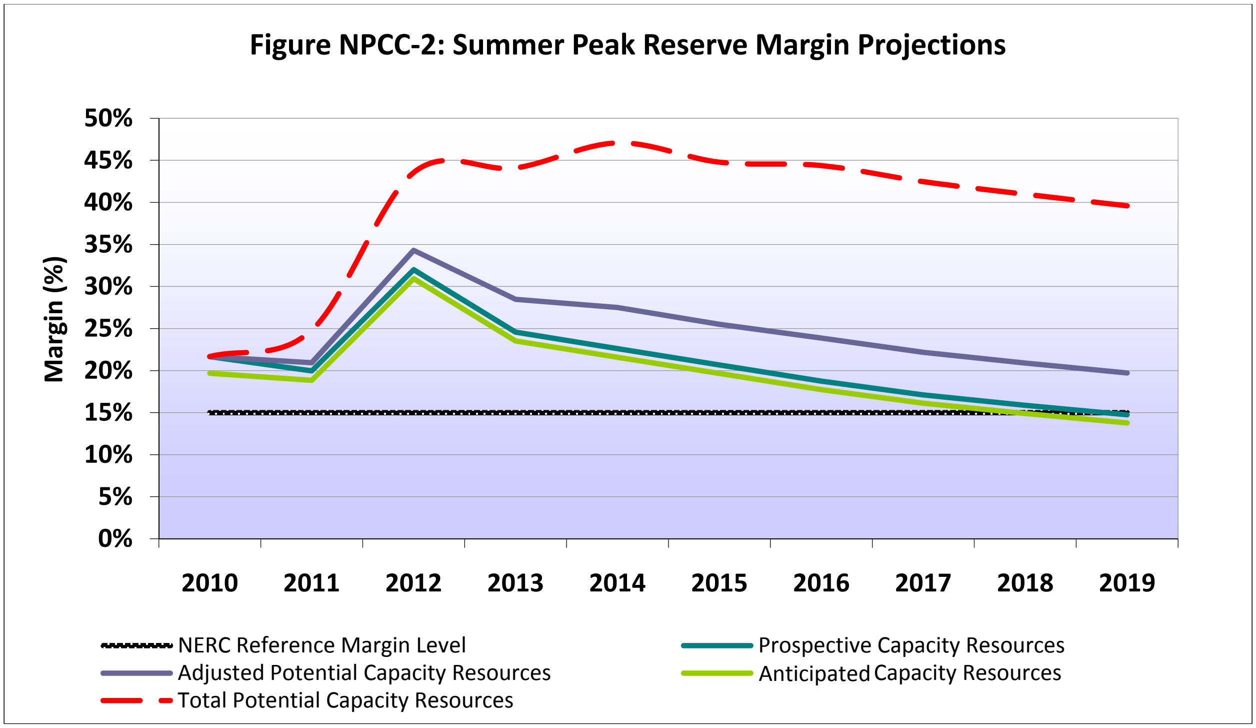
The August 2010 Existing-Certain Capacity & Net Firm Transactions is 32,539 MW, which results in an Existing-Certain and Net Firm Transactions Reserve Margin of 19.7 percent of the reference demand forecast of (27,190 MW). This Reserve Margin reflects the resources (both supply & demand side) that have Capacity Supply Obligations (CSOs) to serve the Regional demand and operating reserve requirements as a result of ISO-NE's auctions within the FCM.

In the 2011 summer, the Existing-Certain and Net Firm Transactions Reserve Margin increases to 24.0 percent and then decrease to 21.0 percent in the 2012 summer. These variations are the results of the annual capacity auctions within FCM. It was assumed that resources with CSOs for 2012/2013 will remain in place through the end of the assessment period. Without any assumed new capacity resources, the Existing-Certain and Net Firm Transactions Reserve Margins declines to 4.6 percent by 2019.

[170] To ensure the New England's power system has adequate capacity resources, ISO-NE must first determine the Regional Installed Capacity Requirement (ICR), which forms the basis of the system-wide total amount of new and existing resources that must be procured through the annual FCAs as part of the FCM. The ICR is determined using the well-established probabilistic loss-of-load-expectation (LOLE) analysis. The LOLE analysis identifies the amount of installed capacity (MW) the system needs to meet the NPCC and ISO-NE resource adequacy planning criterion to not disconnect firm load more frequently than once in 10 years. To meet this "once-in-10-years" LOLE requirement, a bulk power system needs installed capacity in an amount equal to the expected demand plus additional capacity to handle any uncertainties associated with load or the performance of the capacity resources. The analysis for calculating the ICR for New England examines system resource adequacy using assumptions for the load forecast, resource availability, and possible tie-reliability benefits (*i.e.*, the receipt of emergency electric energy from neighboring Regions). The model also accounts for the load and capacity relief that can be obtained from implementing operating procedures, including load-response programs. The ICR calculation, which uses a single-bus model, does not consider the transmission system constraints within New England. In addition to resources located in New England, the ICR analysis models all existing qualified imports, as reported within ISO-NE's 2010 CELT Report.

[171] 1,898 MW of demand-side resources divided by 32,792 MW of Total Internal Capacity.

[172] The US DOE 2009 Congestion Study Report is available at the following link: http://www.congestion09.anl.gov/documents/docs/Congestion_Study_2009.pdf



New England does not have a particular capacity or reserve margin requirement; rather it projects its capacity needs to meet the NPCC once in ten-year loss of load expectation (LOLE) resource planning reliability criterion. To develop installed capacity requirements to meet the once in ten-year disconnection of firm load resource planning reliability criterion, ISO-NE takes into account the random behavior of demand and resources in a power system, and the potential load and capacity relief obtainable through the use of various ISO-NE Operating Procedures. The capacity needs to meet this criterion are purchased through annual auctions (FCAs) three years in advance of the year of interest. After this primary auction, there are Annual Reconfiguration Auctions (ARAs) prior to the commencement year, in order to readjust installed capacity purchases and ensure that adequate capacity will be purchased to meet system needs. Therefore, ISO-NE does not expect to face any installed capacity shortages in the future.

Table NPCC-5 summarizes the 50/50 peak demand forecast, the net ICR values for the 2010/2011 through 2013/2014 capacity commitment periods, the representative net ICR values for the 2014/2015 through 2019/2020 periods, and the percentage of the resulting reserves.[173] The net ICR values for the 2010/2011 through 2013/2014 capacity commitment periods, which are calculated as the ICR minus the value of Hydro-Québec Installed Capability Credit (HQICC) for the particular capability year, reflect the latest ICR values established for those years. The ICR and HQICC values for the 2010/2011 through 2013/2014 commitment periods have been approved by FERC. The representative net ICR values for

[173] Resulting reserves are the amount of capacity in excess of the forecast 50/50 peak demand. Percent resulting reserves = [{(Net ICR − 50/50 peak demand) ÷ 50/50 peak demand} × 100].

2014/2015 and beyond were calculated by ISO-NE with stakeholder input using the following assumptions:

- The availability of 1,700 MW of total tie-line benefits from the three neighboring balancing authority areas of Québec, the Canadian Maritime provinces, and New York
- 2010 CELT Report demand forecast
- Generating and demand-resource capability ratings, availability, and performance metrics, based on the values used to calculate the ICR for the fourth FCA for the 2013/2014 capability period.[174]

As shown in Table NPCC-5, the percentage of resulting reserve associated with the net ICR values for 2010/2011 and 2011/2012 are 1% to 2% higher than the resulting reserves percentage values for the rest of the assessment years. This is because the demand forecasts used to calculate these net ICRs were slightly higher than the demand forecasts used to calculate the resulting reserve percentages for the later years.[175] Table NPCC-5 also shows that the annual resulting reserves calculated using the net ICR values increase from 12.5% in 2013/2014 to 13.3 % by 2019/2020. This increase in the percentage of resulting reserves is a result of assuming a fixed amount of tie benefits through time. As the system demand increases and the tie benefits stay constant, the installed capacity needed to meet the resource adequacy planning criterion increases as a percentage of the peak demand.

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[174] ISO-NE filed the ICR filing with FERC on May 4, 2010, and is available at: http://www.iso-ne.com/regulatory/ferc/filings/2010/may/er10-   -000_05-04-10_icr_2013-2014.pdf

[175] ISO-NE filed the 2011/2012 ICR on September 9, 2008, and was based on the 2008 demand forecast which is available at http://www.iso-ne.com/regulatory/ferc/filings/2008/sep/er08-1512-000_9-9-08_2011-2012_icr_filing.pdf . The 2010/2011 ICR for the annual reconfiguration auction (not the primary FCA) was filed by ISO-NE on January 30, 2009, and also used the 2008 demand forecast; http://www.iso-ne.com/regulatory/ferc/filings/2009/jan/er09-640-000_1-30-09_icr_filing.pdf .

Table NPCC-5: Actual and Representative Future New England Net Installed Capacity Requirements for 2010-2019 and Resulting Reserves (percent)

Year	Forecast 50/50 Peak Demand	Actual and Representative Future Net ICR [176]	Resulting Reserves (percent)
2010/2011	27,190	31,110	14.4
2011/2012	27,660	31,741	14.8
2012/2013	28,165	31,965	13.5
2013/2014	28,570	32,127	12.5
2014/2015	29,025	32,672	12.6
2015/2016	29,450	33,178	12.7
2016/2017	29,785	33,604	12.8
2017/2018	30,110	34,025	13
2018/2019	30,430	34,434	13.2
2019/2020	30,730	34,818	13.3

[176] "Representative Future Net ICR" is the representative ICR for New England, minus the tie-reliability benefits associated with the HQICCs. The ICR value for 2010/2011 reflects the value for the third Annual Reconfiguration Auction (ARA #3) approved by FERC in its February 12, 2010, *Order Accepting ISO New England's Proposed Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits, Related Values, and Tariff Changes, subject to Condition* (http://www.iso-ne.com/regulatory/ferc/orders/2010/feb/er10-438-000_2-12-10_icr_jump_ball_order.pdf). The ICR value for 2011/2012 reflects the ARA #2 value accepted for filing by FERC in its March 29, 2010, *Order Accepting for filing the Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the Second Reconfiguration Auction for the 2011/2012 Capability Year* (http://www.iso-ne.com/regulatory/ferc/orders/2010/mar/er10-714-000_3-29-10_ltr_order_accept_2011-2012_icr.pdf). For the 2012/2013 capability year, the net ICR value represents the value approved by FERC in its August 14, 2009*, Filing of Installed Capacity Requirement, Hydro-Quebec Interconnection Capability Credits and Related Values for the 2012/2013 Capability Year.*

(http://www.iso-ne.com/regulatory/ferc/orders/2009/aug/er09-1415-000_8-14-09_accept%202012-2013%20icr.pdf). For the 2013/2014 Capacity Commitment Period, the net ICR value represents the value filed with the FERC on May 4, 2010. The 2014/15 through 2019/2020 capability years' representative net ICR values reflect the amount of capacity resources needed to meet the resource adequacy planning criterion.

The amount of Total Internal Capacity, both supply and demand-side, which is assumed available to meet the Installed Capacity Requirement, is 32,792 MW in the 2010 summer, decreasing to 31,134 MW for the 2011 summer, then increasing to 35,354 MW in 2012. The 2012 amount, 35,354 MW is held constant through each summer from 2013 to 2019. The amount of resources external to New England reflects Net Firm Capacity Imports of 288 MW in 2010, 2,050 MW in 2011, 1,820 MW in 2012, 234 MW in both 2013 and 2014, and then decreases to Net Firm Capacity Exports of 94 MW by 2019. There is no reliance on emergency imports, reserve sharing or outside assistance/external resources to satisfy Net Internal Demand, other than those transactions identified above.[177]

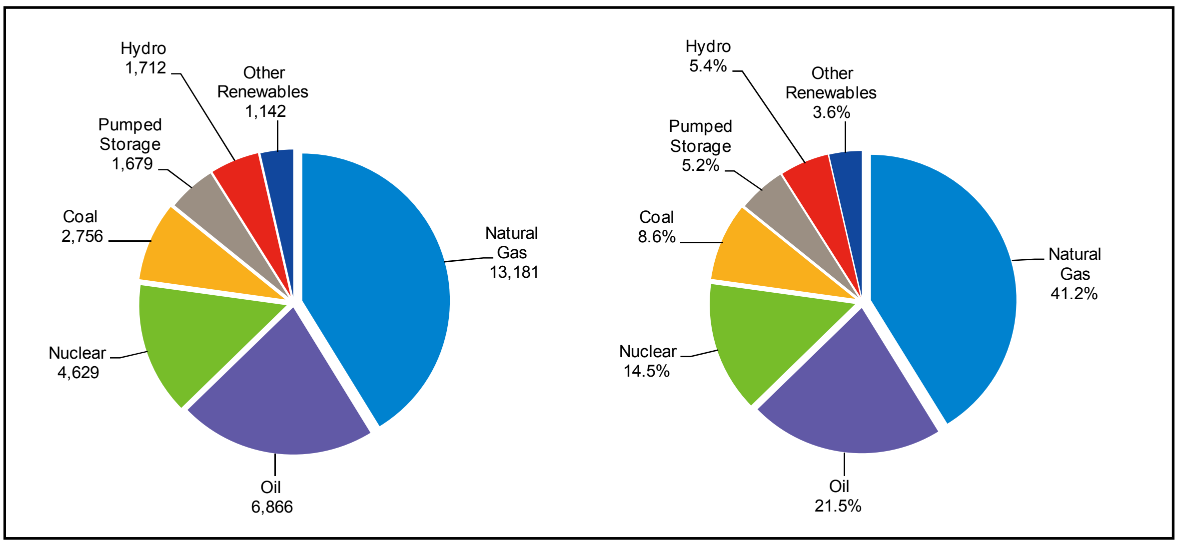
The New England subregion of NPCC does not treat short-term (1-5 years) and long-term (6-10 years) Reserve Margin requirements differently, although more attention is paid to the short-term Reserve Margins due to their applicability in forecasting resource adequacy requirements.

Figure NPCC-3 shows New England's 2010 summer capacity (MW) and overall contribution percentages (%). Total 2010 summer capacity is 31,965 MW.

Figure NPCC-3

2010 Summer Capacity (MW & %)

(31,965 MW Total)



Due to the major contribution to overall capacity from gas-fired capacity (13,181 MW at 41.2 percent), fuel supply disruptions to Regional gas-fired generation can affect resource adequacy.[178,179] However,

[177] In the determination of the ICR, ISO-NE does include approximately 1,665 MW – 2,000 MW of "Tie-Benefits" from neighboring systems, to deliver emergency or outside assistance, in the event of a capacity deficiency.

[178] All fuel type amounts and percentages are based on each generator's reported primary fuel type.

because the majority of these facilities are direct-connect customers of five large, Regional interstate gas pipelines, the simultaneous loss of gas supply or downstream-transmission to all these five interstate pipelines is improbable. The temporary loss of gas supply or gas transmission capacity on any individual pipeline could still affect resource adequacy, although at a much smaller and localized level. In general, the low priority nature of Regional gas-fired generators' fuel supply and transportation entitlements can create temporary operable capacity problems, primarily during winter, when most of the Regional pipelines are fully subscribed and flowing natural gas to firm customers of the Regional gas LDCs.

Due to the contribution to overall capacity from oil-fired facilities (6,866 MW at 21.5 percent), fuel supply disruptions to Regional oil-fired facilities (some of which are dual-fuel capable) could impact resource adequacy, although on-site oil storage inventories at these facilities is usually in the 5-15 day supply range. It is assumed that most dual-fuel units would swap over to their unconstrained fuel supply. Therefore, temporary fuel supply disruptions to oil-fired facilities should not be problematic.

Approximately 8,106 MW or 25.4 percent of overall installed capacity is dual fuel capable, burning a combination of natural gas or heavy or light fuel oil. These dual fuel units can contribute to system reliability when either natural gas or oil supplies become constrained, by switching over to their unconstrained fuel source.

Due to the minor contribution to overall capacity from coal facilities (2,756 MW at 8.6 percent), fuel supply disruptions to Regional coal facilities would have a minor impact on resource adequacy. On-site coal inventories are usually in the 15-30 day supply range. Therefore, temporary fuel supply disruptions at coal facilities should not be problematic.

Due to the relatively small contribution to overall capacity made by hydro-electric facilities (1,712 MW at 5.4 percent); Regional drought conditions could reduce hydro-electric energy production, which however, would be readily supplemented by increased levels of other types of fossil-based generation.

The New England area is currently not experiencing a drought. However, in the event that the Region was experiencing an extended drought, some traditional hydro-electric stations could be temporarily capacity constrained. Other fossil stations could also be temporarily capacity limited due to lack of cooling water or other (heat-related) environmental issues. As noted earlier, due to the relatively small contributions to the Regions overall installed capacity from hydro-electric facilities, drought conditions could cause a temporary disruption in both hydro-electric and fossil-based energy production, which would in turn need to be supplemented by increased levels of other generation.

ISO-NE's Operating Procedure No. 21 – *Action during an Energy Emergency* (OP21)[180] addresses energy emergencies, which may occur as a result of sustained national or Regional shortages in fuel availability or deliverability to New England's generation resources. Because fuel shortages may impact the Region's

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[179] Of the 41.2 percent of the New England generators that use natural gas as their primary fuel, about 43 percent (5,603 MW) are dual-fuel capable and use fuel oil as their secondary fuel source.

[180] OP21 is located on the ISO-NE web site at: http://www.iso-ne.com/rules_proceds/operating/isone/op21/index.html

ability to fully meet system demand and operating reserves for extended periods of time, actions may need to be taken in advance of a projected energy emergency. OP21 specifies actions to commit, schedule, and dispatch the system in such a way as to preserve stored fuel resources in the Region to minimize the loss of operable generating capability due to fuel shortages. OP21 can be implemented to mitigate most types of fuel shortages impacting the electric sector, no matter what the triggering event may have been, *i.e.* destruction of oil and natural gas infrastructure due to hurricanes, loss of major transmission pathways due to earthquakes or damage from ice storms, frozen harbors or frozen coal piles, and/or delivery disruptions of oil and LNG.

In addition, ISO -NE does not consider any energy-only, existing-uncertain wind or transmission-limited resources in its resource adequacy assessment.

Renewable Portfolio Standards (RPS) do not affect resource adequacy in New England in a direct way. RPS are state legislated targets generally applicable to competitive retail electric suppliers to obtain a specific percentage of their energy from renewable resources or pay an Alternative Compliance Payment (ACP) for any deficiency. The ACP serves as a price cap and can be used to fund new renewable projects. The revenues from the associated Renewable Energy Credits (RECs) can create financial incentives to build renewable resources. The RPS target usually grows each year and is broken down by specific “Classes” for existing and new resources and, in some states, special technology categories. The “new” classes of RPS have an increasing percentage of renewable resources for a state’s supply mix goals. The widespread use of intermittent resources can poses some technical challenges and some states have related goals for Energy Efficiency, which could then reduce the need for supply-side RPS resources. Increases in renewable resources leads to increased fuel diversity, which has a positive impact on system reliability. Table NPCC-6 identified the New England States’ RPS Classes and Energy Efficiency for the target year 2020.

Variable resources are treated as any other resource in ISO-NE’s resource adequacy assessment, in that they are expected to provide their CSO. Their CSO cannot exceed their Qualified Capacity, which is based on historical generation during on-peak hours for existing resources, or on engineering data for new resources.

ISO-NE has instituted several processes to aid in the integration of variable resources into ISO planning and operations. ISO-NE has recently concluded a study for the New England Governors that provides a transmission planning service focused on the integration of renewable and carbon-free energy resources into New England’s power grid. ISO-NE also assists the New England States in coordination with the Region’s Transmission Owners in the development of a long-term plan for the New England transmission system that incorporates the unique attributes and goals of each state and the possibility of additional renewable or carbon-free electricity imports from neighboring Regions. ISO-NE also provides performance and impact evaluations on various transmission and generation scenarios from both a reliability and economic perspective.

Table NPCC-6: New England States' RPS Classes and 2020 Targets[181]		
State	**Classes**	**RPS Target by 2020 (%)**
Maine	Existing	30%
	New Capacity	10% of Capacity by 2017
New Hampshire	I New	11%
	II Solar	0.30%
	III Existing Biomass	6.50%
	IV Existing Small Hydro	1.00%
Massachusetts	New	15%
	Existing I & II	3.6% & 3.5%
	EE	All new Energy Growth
Rhode Island	Existing	2%
	New	14%
Connecticut	I New	20%
	II Existing	3%
	III CHP and EE	4%
Vermont	{Has no formal RPS}	20% Goal by 2017
	SPEED Program	All Energy Growth Above 2005

ISO-NE is finalizing a Wind Integration Study that focuses on what is needed to effectively plan for and integrate wind resources into system and market operations. The main part of the study focused on developing a mesoscale and wind plant model for the New England area, including onshore and offshore capability. Using these models, the study looked at several wind development scenarios to determine their impact on unit commitment practices, scheduling, automatic generation control, reserves, market operations and rules as well as other key elements of the system. Another important component of the

[181] EE – Energy Efficiency
CHP – Combined Heat & Power
SPEED – Sustainably Priced Energy Enterprise Development System

study will be to plan for and develop technical requirements for new wind resources interconnecting to the system, including the provision for data collection to develop a state of the art wind forecasting tool to use in system and market operations.

Within ISO-NE's FCM, qualifying Demand Response (DR) (including Energy Efficiency) is treated as supply-side capacity. Within FCM, DR are installed measures (*i.e.*, products, equipment, systems, services, practices or strategies) that result in additional and verifiable reductions in end-use electricity demand. These verifiable reductions serve to reduce the peak demand on the system and maintain operating reserves, avoiding the dispatch of additional generation. DR can displace demand permanently, over pre-defined hours or in real-time when dispatched by the ISO-NE. The minimum size of DR in FCM is 100 kW. ISO-NE's FCM DR resources can be made up of smaller DR assets (< 100 kW) which can then be aggregated into a demand-side portfolio of FCM resources of size 100 kW and above.

Within ISO-NE's FCM, DR is separated into two (2) categories;

1. Passive DR - Includes both On-Peak & Seasonal Peak components. This Passive DR is defined at the load zone level, non-dispatchable, and should reduce energy demand during peak hours.
2. Active DR - Includes both Real-Time Demand Response (RTDR) & Real-Time Emergency Generation (RTEG) components. Active DR is defined at the dispatch zone, is operated based on real-time system conditions via dispatch by ISO-NE, and reduces energy demand during "reliability" hours.

Energy Efficiency (EE) is also taken into account within FCM. EE resources in the FCM are treated as supply-side capacity that can contribute to meeting the Region's ICR. ISO-NE's demand forecast also reflects the contribution of non-FCM EE and federal appliance efficiency standards. However, at this time, estimates of State EE Program are not uses to reduce the ICR or demand forecast. ISO-NE and Regional Stakeholders are currently in discussion concerning this and other related issues.

ISO-NE has not received applications for any future unit retirements that potentially could have a significant impact on reliability, although the potential for retirements may be considered part of system design. Nuclear plant relicensing, *once-through* cooling issues and aging generation are the major retirement concerns facing New England at this time.[182] In the event that the owners of these nuclear plants are not able to obtain renewal of their operating permits, the owners of the fossil-steam units that use *once-through* cooling, or the owners of the aging generation choose to retire their affected facilities, the lost capacity will be procured through the ISO-NE's FCM, either in the form of new generation, imports or Demand Response. At several fossil-steam units, the replacement of once-through cooling systems with closed-loop cooling systems (*i.e.*, cooling towers) would be managed through planned outages which would be coordinated by ISO-NE to minimize the impact on system reliability. ISO-NE has observed actions taken in the state of Vermont with respect to the relicensing efforts for Vermont Yankee. While Vermont Yankee has not formally notified ISO-NE of its potential

[182] As noted earlier, approximately 1,281 MW of nuclear capacity has their NRC Operating License expiring within two years.

retirement, ISO-NE is adding the retirement of Vermont Yankee to its assumptions when updating assessments of this area.

At this time, there are no plans to install more Under Voltage Load Shedding (UVLS) in New England. Currently, northern New England has the potential to arm approximately 600 MW of load shedding as part of UVLS. However, it is important to recognize that a significant portion of this load shedding is normally not armed and is only armed under severe loading conditions with a facility already out of service. Presently, two significant projects will either completely eliminate the need for the UVLS or significantly reduce the likelihood of depending on such schemes. These projects are the Vermont Southern Loop Project and the Maine Power Reliability Program (MPRP).

There are no special protections system schemes (SPS) that are proposed to be installed in lieu of proposed regulated transmission facilities to address system reliability needs in New England in assessment timeframe. However, a new, temporary SPS was recently installed in Southern Maine as part of the MPRP. This SPS is needed to ensure reliable system operation due to configuration changes at South Gorham, while the MPRP is under construction. Once construction of the necessary portions of the MPRP is complete in approximately 2014, this SPS will no longer be needed.

As an NPCC subregion, ISO-NE is bound to comply with NPCC's *Regional Reliability Reference Directory # 1 - Design and Operation of the Bulk Power System.*[183] Within this Reliability Reference (document), NPCC mandates that ISO-NE perform annual assessments of potential contingencies or topologies that could impact bulk power system operation. One subset of this analysis is the *"Extreme System Conditions Assessment"* which dictates that ISO-NE transmission planners assess several types of *"low probability"* events or scenarios in order to understand potential outcomes.[184][185] These types of assessments are based on transmission analysis. The NPCC *Regional Reliability Reference Directory #1* does not mandate a solution set(s) to these potential events, scenarios or topologies. ISO-NE also performs similar assessments with respect to resource adequacy, however, these assessments are not routine and are usually performed on an as needed basis. These analyses typically assess extreme contingency testing, such as a loss of a major gas pipeline, and are performed to determine the effect of such a contingency on the New England transmission system performance as a measure of system strength. Plans or operating procedures may be developed to reduce the probability of occurrence or to

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[183] Located at: http://www.npcc.org/documents/regStandards/Directories.aspx

[184] "The bulk power system can be subjected to wide range of other than normal system conditions that have low probability of occurrence. One of the objectives of extreme system conditions assessment is to determine, through planning studies, the impact of these conditions on projected steady-state and dynamic system performance. This is done in order to obtain an indication of system robustness or to determine the extent of a widespread system disturbance. Each Transmission Planner and Planning Coordinator has the responsibility to incorporate special simulation testing to assess the impact of extreme system conditions. Analytical studies shall be conducted to determine the effect of design contingencies under the following extreme conditions; 1) Peak load conditions resulting from extreme weather conditions with applicable rating of electrical elements, 2) Generating unit(s) fuel shortage, (*i.e.*, gas supply adequacy). After the assessment of extreme system conditions, measures may be used, where appropriate, to mitigate the consequences that are indicated as a result of testing for such system conditions."

[185] This similar type analysis is also mandated within ISO-NE Planning Procedure 03 - *"Reliability Standards for the New England Area Bulk Power Supply System"* (PP03).

mitigate the consequences that are indicated as a result of the extreme contingency testing. As part of the latest ISO-NE Comprehensive Area Review for year 2013, extreme system condition testing evaluated the loss of an interstate gas pipeline in order to simulate generating unit fuel shortages in New England. The results of the analysis were found acceptable and did not result in the development of any new operating plans or procedures.

Transmission plans continue to be developed to serve demand growth throughout the New England Region. This includes service to demand areas in Maine, New Hampshire, Vermont, Western Massachusetts, Southeastern Massachusetts, Northeastern Massachusetts, Greater Rhode Island and Connecticut. Future resources are included in reliability assessments only if they have received an obligation through the FCM, are contractually bound by a state-sponsored RFP, or have a financially binding obligation pursuant to a contract. However, assessments still consider reasonable planned and unplanned outages of the future resources in the same manner as existing resources.

Maine – The Maine Power Reliability Program (MPRP) analyses have identified the potential for difficulties in moving power into and through Maine to various load pockets spread throughout the state under stressed conditions. The existing system is highly dependent upon the 345 kV lines which consist of only a single 345 kV path in the north and two parallel 345 kV paths in the south. Furthermore, there are a limited number of 345/115 kV autotransformers to supply the 115 kV network. System studies have shown that loss of a single 345 kV transmission line or autotransformer can yield unacceptable results, which are further exacerbated when a second contingency is contemplated. The largest of these pockets is the area in southern Maine along the seacoast, which includes the Portland area. An area in Maine, often referred to as western Maine, is challenged to supply area demand, which includes a number of large paper mills, especially when these demands are modeled at their contractual limits. Additionally, there are a number of SPS which have become a significant concern in real-time operations and have also been shown to become inadequate in the future. The MPRP effort proposes numerous system additions to address these concerns. At a high level, these upgrades would create a new 345 kV path, extending from the Orrington substation in central Maine to the Three Rivers switching station located in southern Maine. This project also adds a number of 345/115 kV autotransformers and creates a new 115 kV path into western Maine. Until the MPRP is placed in service, system operators will rely heavily on available resources and SPS in the area to ensure the reliability of the system.

New Hampshire – A ten-year study of the New Hampshire area has initially identified the potential for system concerns throughout much of the state for numerous different contingencies and resource outages. The more significant concerns are related to serving the southern and seacoast areas, which are served from a limited number of autotransformers and insufficient 115 kV networks. Further concerns are related to moving power into central New Hampshire, which is served through a 115 kV path and serving northern New Hampshire following the loss of the single 230/115 kV autotransformer at Littleton. These concerns are addressed through the planned addition of new autotransformers in the seacoast, southern and northern areas, coupled with new transmission. The exact configuration of the new transmission is under review. The study of New Hampshire's system is under review largely due by the potential retirement of Vermont Yankee as well as reductions in the Regional demand forecast. The review is necessary to reflect changes to future assumptions within Vermont, which may impact the performance of the New Hampshire transmission system.

Vermont – A ten-year study of the Vermont area has identified the potential for system concerns moving power through the state for various future contingencies. Due to limited generation supplies and a significant demand concentration in the northern part of the state, power must be imported over significant distances to serve this area. Therefore, when either a southern 345 kV line or a key 345/115 kV autotransformer in the state is lost, the next critical contingency would result in numerous thermal and voltage violations in Vermont, as well as facilities in neighboring states. Solutions to these concerns include providing additional reactive support, adding new autotransformers, reconductoring a number of 115 kV lines, or adding a new 230/345 kV circuit into Vermont. The study of Vermont's system is under review largely due by the potential retirement of Vermont Yankee as well as reductions in the Regional demand forecast. The review is necessary to reflect changes to future assumptions within Vermont.

Connecticut – The New England East - West Solution (NEEWS) studies have included the evaluation of both the ability of the system to move power from East to West across southern New England and the ability to move power into and across Connecticut. Past analyses had indicated that Connecticut would need either transmission improvements or over 1,500 MW of supply or demand-side resources by 2016. Past studies also showed that Connecticut had internal transmission elements that limited east–west power transfers across the central part of the state. The movement of power from east to west in conjunction with higher import levels to serve Connecticut had resulted in overloads of transmission facilities located within the state. Updated assessments have shown that resources planned and obligated by contract for Connecticut are sufficient to meet reliability requirements for 2010 and 2011, assuming no supply-side resource retirements. In the absence of additional resources, the proposed solution involves new interstate 345 kV transmission lines from central and western Massachusetts into Connecticut, which eliminate the existing constraints.

Southwest Connecticut – Issues identified in the long-term reliability Needs Assessment for the area of southwest Connecticut consist of thermal overloads and low voltage violations. Alternatives to address these concerns and deficiencies are under study.

Massachusetts

- **Boston Area** – A long-term reliability Needs Assessment has been completed for the Greater Boston area. Various transmission contingencies result in overloads of 115 kV transmission facilities and low voltages in the area. Alternatives under consideration consist of a mix of new 345 kV and 230 kV transmission lines as well as 345/230 kV and 230/115 kV transformation.

- **Berkshire County/Pittsfield Area –** A Needs Assessment has identified needs for the Berkshire County/Pittsfield area in western Massachusetts. Under certain system conditions, the study identified overloads on various 115 kV transmission lines and the 345/115 kV autotransformer at Berkshire. Low voltage violations were observed at several substations in the area. Possible solutions to these issues include adding 345/115 kV autotransformers, upgrading long segments of old 115 kV transmission lines, and installing additional capacitors to mitigate both thermal and voltage concerns.

- **Springfield (MA)** – The NEEWS studies, resulting in part in the Greater Springfield Reliability upgrades, have found that local double-circuit tower outages, stuck-breaker outages, and single-element outages result in severe thermal overloads and low voltage conditions. These overloads are exacerbated when Connecticut transfers increase, especially with a major 345 kV line out of service. The proposed solution eliminates a number of multi-circuit towers in the area and installs a new 345 kV line between Ludlow, Massachusetts and north-central Connecticut.

Rhode Island – The Greater Rhode Island studies, in conjunction with the NEEWS studies, have identified significant thermal constraints on the 115 kV system. The outage of any one of a number of 345 kV transmission lines results in limits to power transfer capability into Rhode Island. With a line out of service, the next critical contingency would result in numerous thermal and voltage violations, and possibly the shedding of over 500 MW of demand. This could be resolved by transformer additions, a new 345 kV line between West Farnum and Kent County, and the additional central Massachusetts to Connecticut 345 kV line (mentioned above) being looped into the West Farnum substation.

There are no known existing reactive power-limited areas within New England's transmission system. The studies described above have documented the upcoming reactive power needs of the system. Transmission planning studies have ensured that adequate reactive resources are provided throughout New England. In instances where dynamic reactive power supplies are needed, devices such as STATCOMs, SVC's, Synchronous Condensers, and DVARs have been employed to meet the required need. If additional reactive power support is necessary in real-time, supplemental generation commitment has been employed to meet the required need. Additionally, the system is reviewed in the near-term via operating studies to develop operating guides to confirm adequate voltage/reactive performance.

In creating transfer limits based on the dynamic performance of the system, New England applies a 100 MW margin to transfer limits.

New England already has a number of installations of new technologies. These include two STATCOMs, voltage source converter based HVdc, variable reactors, a short section of gas-insulated transmission line (GITL), synchronous condensers, and D-VAR. These types of technologies are always under consideration as tools to address future system concerns.

Under EPRI Management, ISO-NE participates in a project aiming for the development of a new tool for on-line identification of potential cascading outages (blackout) events. Current operating practice, based on N-1 security criteria cannot guarantee the avoidance of cascading failures from multiple contingencies or outages occurring in a rapid succession. This new on-line tool will identify initiating events, which can potentially lead to cascading outages. These initiating events, in addition to traditional contingencies, will be supplied to dispatch software, and will be furnished to the System Operator as an advance notification of potential threats to the power system.

Smart grid programs within New England include reliability-based and price-based Demand Response programs, non-generation technologies such as energy storage, providing regulation service, and distributed generation such as wind and solar, etc.

ISO-NE has received U.S. DOE Smart Grid Investment Grant Award and has begun the three-year Synchrophasor Installation and Data Utilization (SIDU) project starting July 1, 2010. The New England SIDU project has three major components:

1. Installation of over 30 Phasor Measurement Units (PMU) across the New England transmission grid.
2. Providing the enhanced Phasor Data Concentrator (PDC) by customizing and refining the Flexible Integrated Phasor System (FIPS), thus enabling New England Transmission Owners and ISO-NE to collect and share synchrophasor data with other Regions for wide-area monitoring.
3. Developing an application called *"Region of Stability Existence (ROSE)"* which uses the real-time PMU data to assess stability and reliability of the power grid. It will allow operators to better predict steady-state instability within the real-time environment and provide remedial action to protect system reliability and help avoid blackouts.

As noted earlier, the uncertainty and variability of wind and solar resources may pose operational challenges. The New England Wind Integration Study (NEWIS) is investigating the operational impacts of different penetration levels of wind resources. The study will also recommend changes in operating practices and procedures to accommodate a large-scale penetration of wind resources.

There are no other project slow-downs, deferrals, cancellations, etc which may impact reliability in New England.

OTHER REGION-SPECIFIC ISSUES

In anticipation for the potential for a large amount of wind generation to be developed within the New England Region over the next ten-year period, ISO-NE is finalizing a Wind Integration Study that focuses on what is needed to effectively plan for and integrate wind resources into system and market operations. The main part of the study will focus on developing a mesoscale and wind plant model for the New England area, including onshore and offshore capability. Using those models, the study will look at several wind development scenarios to determine their impact on unit commitment practices, scheduling, automatic generation control, reserves, market operations and rules as well as other key elements of the system. Another important component of the study will be to plan for and develop technical requirements for new wind resources interconnecting to the system, including the provision for data collection to develop a state of the art wind-forecasting tool to use in system and market operations. Finally, the study will look at previous operational studies from around the world and research the most effective tools and processes already in place elsewhere.

ISO-NE is also assisting new wind park developers in understanding the requirements for interconnection and operating in the New England market through a new generator outreach program facilitated by its Market Services Department. Topics that are handled in these sessions are intended to assist in the planning process for the ultimate operation of these resources and focus on areas such as determining telemetry requirements, voice communication requirements and system and market operational readiness.

New England's transmission reliability concerns are addressed through the addition of new resources procured through the Forward Capacity Market, system plans contained in the Project Listing, and as a result of the ongoing planning studies. There are no other transmission reliability issues that need to be discussed for New England.

REGION DESCRIPTION

ISO New England Inc. is a Regional transmission organization (RTO), serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, and also administers the Region's wholesale electricity markets and manages the comprehensive planning of the Regional bulk power system. The New England Regional electric power system serves 14 million people living in a 68,000 square-mile area. New England is a summer-peaking electric system.

NEW YORK SUBREGION

EXECUTIVE SUMMARY

The compound annual demand forecast growth rate for the New York Control Area (NYCA) reported this year is 0.64 percent versus the 0.65 percent reported last year. The primary drivers are a recovery from the recession in the short term and additional Energy Efficiency impacts. Total Internal Demand in the 10th year is projected to be 34,986 MW while the Net Internal Demand is projected to be 34,792 MW.

Capacity classified as "Existing-Certain" resources totals 39,260 MW. This includes 317 MW of new generation added since the prior reporting year and 982 MW of generation retirements. New capacity additions planned to be in-service over the assessment timeframe total 1,941 MW, of which 1,722 MW are combined cycle units. The current Installed Reserve Margin requirement, as determined by the New York State Reliability Council (NYSRC), for the New York Control Area for the Capability Year 2010 – 2011 is 18.0 percent. The projected reserve margins reported on the *2010 Long Term Reliability Spreadsheet* exceed the current required reserve margin throughout the assessment period.

New York State is considering a number of environmental initiatives under the federal Clean Air Act, Clean Water Act and state law that could affect the availability of generation resources in New York or lead to retirements. The NYISO monitors those programs and analyzes their potential reliability impact through its Reliability Needs Assessment (RNA) and Comprehensive Reliability Plan (CRP). At this time, there are no environmental or regulatory restrictions that adversely affect reliability during the 2010-2019 timeframe within the NYCA.

The NYISO's Reliability Planning Process is a long-range assessment of both resource adequacy and transmission reliability of the New York bulk power system conducted over five-year and ten-year planning horizons to ensure that the New York State bulk power system meets or exceeds the planned loss of load expectation (LOLE) that, at any given point in time, is less than or equal to an involuntary load disconnection that is not more frequent than once in every 10 years, or 0.1 days per year. Preliminary results of 2010 RNA demonstrate that the LOLE for the New York Control Area does not exceed 0.10 days per year in any year through 2020 under Base Case conditions.[186]

INTRODUCTION

The NYISO is a not-for-profit corporation responsible for operating New York State's bulk electricity grid, administering New York's competitive wholesale electricity markets, and conducting comprehensive long-term planning for the state's electric power system. The NYISO is regulated primarily by the Federal Energy Regulatory Commission (FERC).

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[186] http://www.nyiso.com/public/webdocs/newsroom/press_releases/2010/2010_Reliability_Needs_Assessment_Final_09212010.pdf

Demand

Last year's compound annual growth rate for the NYCA was 0.65 percent from 2009 to 2018. This year's compound annual growth rate is 0.64 percent from 2010 to 2019. The primary differences between last year's forecast and this year's are a recovery from the recession in the short term and the impact of additional statewide Energy Efficiency programs.

The weather assumptions and economic assumptions for the 50-50 forecast confidence interval case are normal weather and an eventual recovery from the recession.

The NYISO develops independent forecasts for each of 11 zones in its control area; the total is based on the sum of the zones. Both coincident and non-coincident peak demands are forecast. The peak producing conditions are based upon the 50th percentile for most Regions of the state. However, in certain Regions in and around New York City, the peak-producing conditions are more conservative, based upon the 67th percentile. This provides additional reliability for this part of the control area.

Both the current and the previous forecasts have incorporated reductions in peak demand expected to be achieved by statewide Energy Efficiency programs. These programs are funded by the State of New York through system benefits charges applied to all retail rates. The programs are implemented by the New York State Energy and Research Development Agency (NYSERDA), the major investor-owned utilities in the state, and by state power authorities, such as the Long Island Power Authority and the New York Power Authority.

The New York State Public Service Commission has ordered the creation of an Evaluation Advisory Group to develop statewide standards for the measurement and verification (M & V) of the impacts of the programs, after they are installed. This group is currently developing M & V protocols that will be followed by program implementers. Monthly program tracking results are provided to the Department of Public Service staff to determine whether program activities are meeting the goals set by the state.

The NYISO has two reliability-based Demand Response programs: the Emergency Demand Response Program (EDRP) and Installed Capacity (ICAP) Special Case Resources (SCR) program. Both programs can be deployed in energy shortage situations to maintain the reliability of the bulk power grid.

The Emergency Demand Response Program is designed to reduce power usage through the voluntary reduction in demand from businesses and large power users. Companies, mostly industrial and commercial, register with NYISO to take part in the EDRP. The companies are paid for reducing energy consumption when asked to do so. No activations, other than tests, which are required each Capability Period to demonstrate that the resource can achieve the demand reduction registered in the program, have occurred since August 3, 2006.

The Special Case Resources program also seeks to reduce power usage through the reduction of demand from businesses and large power users. Companies, mostly industrial and commercial, register to participate as SCRs. The companies must, as part of their agreement, curtail power usage, usually by shutting down when asked by the NYISO. In exchange, they are paid for their ICAP in advance for agreeing to cut power usage upon request and for the reduced power usage when actually called. No activations, other than tests, which are required each Capability Period to demonstrate that the resource can achieve the demand reduction registered in the program, have occurred since August 3, 2006.

Effective July 1, 2007, NYISO implemented the Targeted Demand Response Program (TDRP) to respond to requests for assistance from a Transmission Owner (TO) by activating EDRP and ICAP/SCR resources on a voluntary basis in one or more subzones. TDRP currently applies to Zone J, New York City, where nine subzones have been defined. No TDRP activations have occurred since August 3, 2007.

The NYISO has two economic programs; (1) the Day-Ahead Demand Response Program (DADRP), which allows energy users to bid their load reductions, into the NYISO's Day-Ahead energy market as generators do, and (2) the Demand-Side Ancillary Services Program (DSASP) that allows energy users to provide ancillary services such as Operating Reserve and Regulation. DADRP bidding and scheduling activity remains frequent, but is limited to only a handful of resources. There are no resources currently enrolled in DSASP.

The NYISO has used substantially the same methods for forecasting loads in 2009 and 2010. An econometric energy forecast is produced for each zone, based on economic and demographic forecasts provided by its economic consultant. A set of zonal load factors are applied to derive the zonal peak coincident demands. The system coincident peak demand is the sum over the zones. A set of zonal diversity factors are applied to derive the zonal non-coincident peak demands from the coincident peak demands. Finally, adjustments are made to each zone for the energy and demand impacts expected from Energy Efficiency programs.

The NYISO constructs a statistical estimate of the 90th percentile and 10th percentile bounds on the base case forecast due to the combined effects of variations in weather and the economy, by modeling the variation in the historic energy and peak data for the preceding 35 years.

GENERATION

Figures 2-1 and 2-2 represent the existing resources in the New York Control Area with a breakdown by fuel type and by GWH production respectively as published in the NYISO's 2010 Load and Data Report (Gold Book).[187]

[187] Load and Data Report: http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

Figure 2-1: 2010 NYCA Capability by Fuel Type

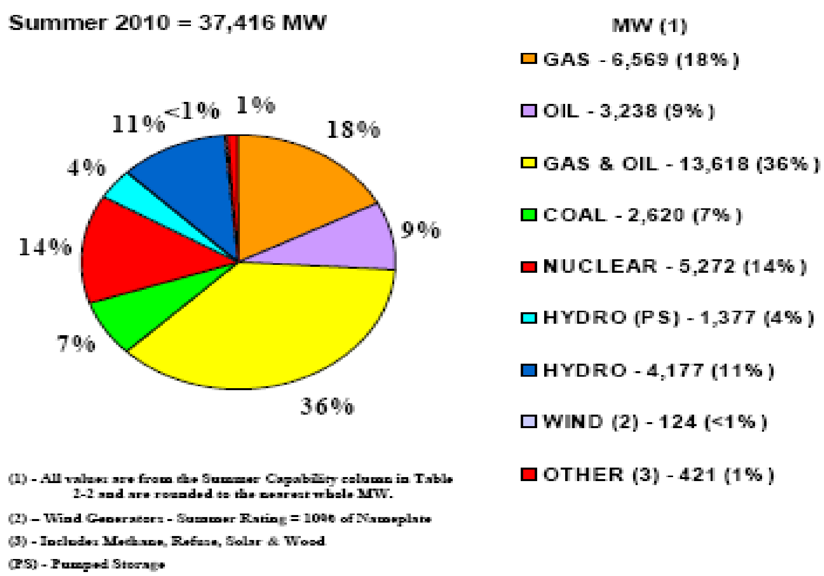
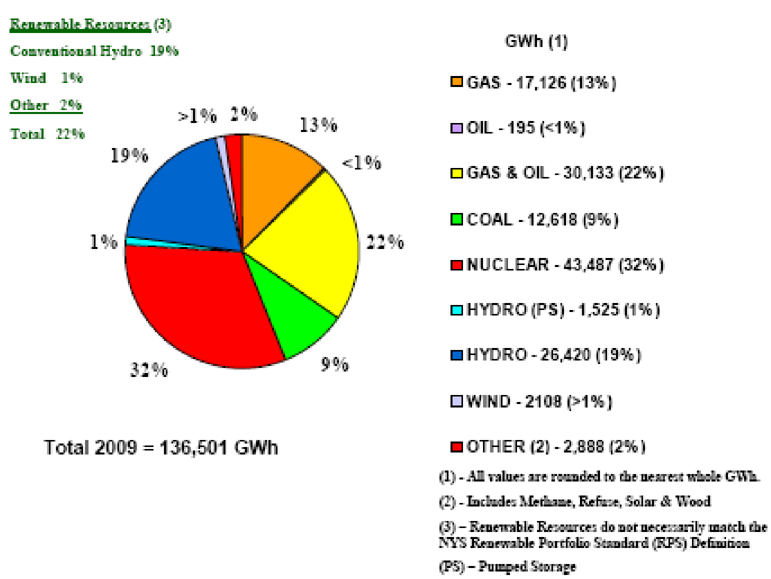


Figure 2-2: 2009 NYCA Generation by Fuel Type



The NYISO maintains a list by Class Year of proposed[188] generation and transmission projects in the NYISO interconnection process. The interconnection process is a formal process defined by NYISO's tariffs by which the NYISO evaluates transmission and generation projects, submitted by Market

[188] The Class Year is the final step in the New York interconnection process where the system upgrade facilities, or "but for" facilities, are determined for proposed new interconnections and cost responsibility for those facilities is assigned.

Participants, developers, and other qualified organizations to determine their impact on system reliability.

Table NPCC-7 represents 1,941 MW of capacity classified as "Future-Planned" resources. These resources have met sufficient milestones for inclusion in the 2010 Gold Book. Table NPCC-8 represents an additional 3,016 MW of capacity classified as "Conceptual." These resource projects were listed in the 2010 Gold Book and are at various stages of study, but at this time it cannot be determined which of these projects are viable and will proceed as planned.

Table NPCC-7: New York Planned Additions

Unit Type	Total MW
Combined Cycle	1,722
Nuclear	168
Hydro	30
Wind	21
Total	**1,941**

Table NPCC-8: New York Conceptual Additions

Unit Type	Total MW
Combustion Turbine	1,594
Flywheel	20
Landfill Gas	6
Solar	32
Wind	1,364
Total	**3,016**

Capacity Transactions on Peak

External capacity (ICAP) purchases and sales are administered by the NYISO. An annual study is performed to determine the maximum level of capacity imports from neighboring control areas allowed without violating the New York Control Area's (NYCA) Loss of Load Expectation (LOLE) criteria. For the Capability Year 2010, the amount is 2,645 MW. Except for Grandfathered Contracts, these Import

Rights are allocated on a first-come, first-served basis with a monthly obligation. While capacity purchases are not required to have accompanying firm transmission, adequate external transmission rights must be available to assure delivery to the NYCA border when scheduled. All external ICAP suppliers must also meet the eligibility requirements as specified in the Installed Capacity Manual.

Unforced Capacity Deliverability Rights (UDRs) are rights associated with new incremental controllable transmission projects that provide a transmission interface to a NYCA locality where a minimum amount of Installed Capacity must be maintained. Three such projects are currently in service with a total transmission capability of 1290 MW. Capacity transactions associated with a UDR are considered confidential market data.

NYCA resources that have sold capacity to an external control area are not qualified to participate in the NYISO ICAP Market, and are not counted as resources eligible to meet the NYCA's LOLE reliability criterion for the period the capacity is sold.

Table NPCC-9 shows the net capacity import transactions for long-term capacity contracts.

Table NPCC-9: Net Capacity Import Transactions by Year (MW)

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
MW	1,542	1,228	1,261	1,952	1,902	1,902	1,902	1,902	1,902	1,902

Transmission

Con Edison's M29 project consists of a 345 kV cable from Sprainbrook to Sherman Creek across the Dunwoodie South Interface. This project is planned to be in service in May 2011. Con Edison is also increasing the rating of two 345 kV cable circuits between Farragut and East 13th St. by installing refrigerated cooling.

The interface into New York City and Long Island from Westchester, New York, namely Dunwoodie South, could become significantly limiting and impact reliability if there are unanticipated delays in new projects, unexpected retirements, or unanticipated load growth. These scenarios are monitored by the NYISO, and if any happen, the NYISO will determine whether there will be a significant reliability impact. If the impact is imminent, the NYISO will request that the New York Transmission Owners (TOs) implement a Gap Solution under the Comprehensive System Planning Process (CSPP). If there is a significant reliability impact to the system that will manifest itself during the next CSPP cycle, the NYISO will address the issue in the next Reliability Needs Assessment.

Operational Issues

There are currently no existing or potential systemic outages that could potentially impact reliability during the 2010-2019 timeframe within the NYCA.

If peak demands are higher than expected the operational measures that can be taken in order to alleviate the situation is to deploy Demand Response programs and/or reserves.

Although various environmental and regulatory policy initiatives are under consideration at the state and federal level, at this time there are no environmental or regulatory restrictions that adversely impact reliability during the 2010-2019 timeframe within the NYCA.

New York State is considering a number of environmental initiatives under the federal Clean Air Act, Clean Water Act and state law that could affect the availability of generation resources in New York or lead to retirements. The NYISO monitors those programs and analyzes their reliability impact through its Reliability Needs Assessment and Comprehensive Reliability Plan.

For the 2010-2019 timeframe within the NYCA there are no anticipated operational changes or concerns resulting from the integration of variable resources.

During peak demand periods, the NYISO's Demand Response programs have proven to be a major contributor to maintaining grid reliability and to the stability of our markets. Since Demand Response resources are only invoked during peak load management situations there are no anticipated reliability concerns resulting from high-levels of Demand Response resources.

Reliability Assessment Analysis

Comprehensive System Planning Process (CSPP) – Overview

Developed with NYISO stakeholders, the biennial Comprehensive System Planning Process (CSPP) combines the expertise of the NYISO and its stakeholders to assess and establish the bulk electricity grid's reliability needs, to develop and evaluate solutions to maintain bulk power system reliability, to identify and assess congestion on the bulk power system, and to evaluate potential projects that mitigate such congestion. Each biennial cycle begins with the Local Transmission Planning Process (LTPP). The LTPP provides inputs for the NYISO's Reliability Planning Process. The NYISO then conducts the Reliability Needs Assessment (RNA). The RNA evaluates the adequacy and security of the bulk power system over a ten-year Study Period. In identifying resource adequacy needs, the NYISO identifies the amount of resources in megawatts (known as "compensatory megawatts") and the locations in which they are needed to meet those needs. After the RNA is complete, the NYISO requests and evaluates market-based and regulated backstop and alternative solutions to address the identified reliability needs. This step results in the development of the NYISO's Comprehensive Reliability Plan (CRP) for the ten-year Study Period. The next step of the CSPP is the completion of the Congestion Assessment and Resource Integration Study (CARIS) for economic planning. CARIS examines congestion on the New York bulk power system and the costs and benefits of alternatives to alleviate that congestion. During the second phase of this step, the NYISO will evaluate specific transmission project proposals for regulated cost recovery.

Reliability Planning Process

The NYISO's Reliability Planning Process is a long-range assessment of both resource adequacy and transmission reliability of the New York bulk power system conducted over five-year and ten-year planning horizons. As an integral part of the CSPP, the Local Transmission Owner Planning Process (LTPP) provides opportunities for stakeholders to have input into each Transmission Owner's system specific plans, which, in turn, are input used in the RNA