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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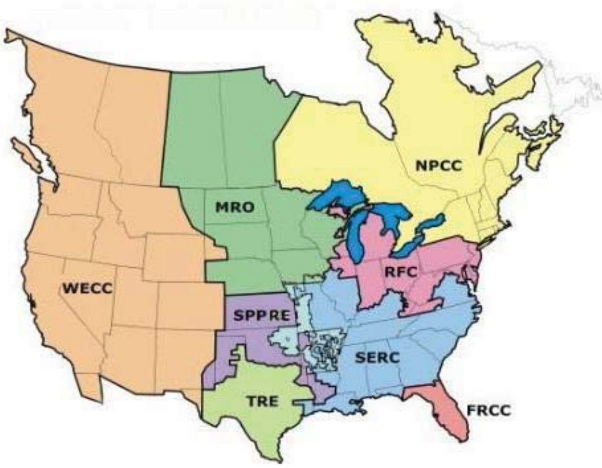
NERC's Mission

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 continues 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

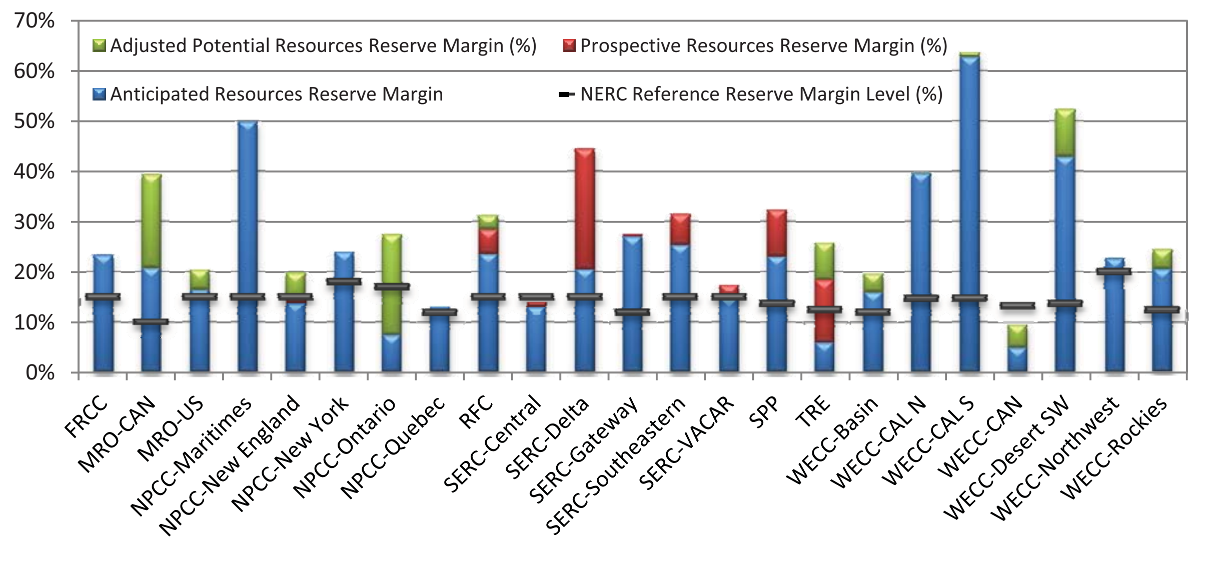
RELIABILITY ASSESSMENT OF NORTH AMERICA

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.

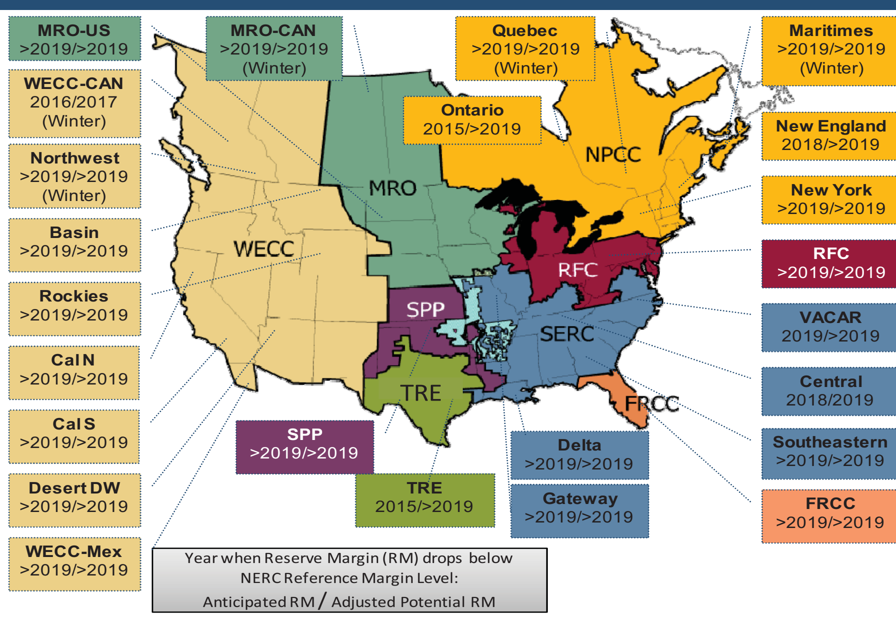
[4] Each Region/subregion may have its own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the Regional/subregional Target Reserve Margin level is adopted as the NERC Reference Margin Level. If not,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

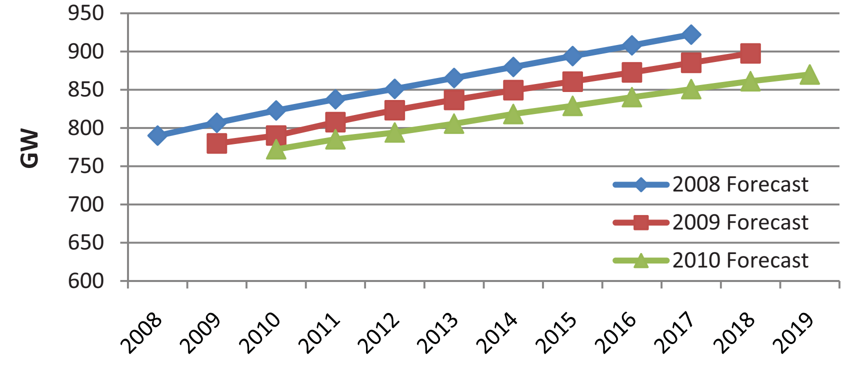
Demand

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.

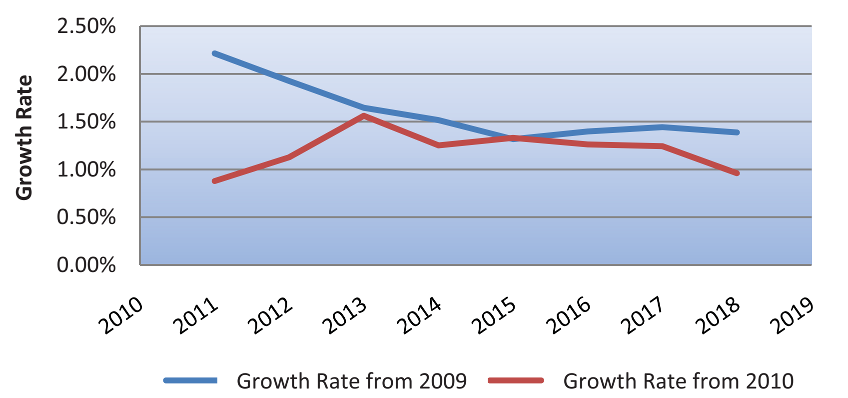
The projections of peak demand and annual Net Energy for Load are aggregates of the Regional forecasts (non-coincident), as of June 2010. These individual forecasts are generally "equal probability" forecast (*i.e.*, there is a 50 percent chance that the forecast will be exceeded and a 50 percent chance 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.

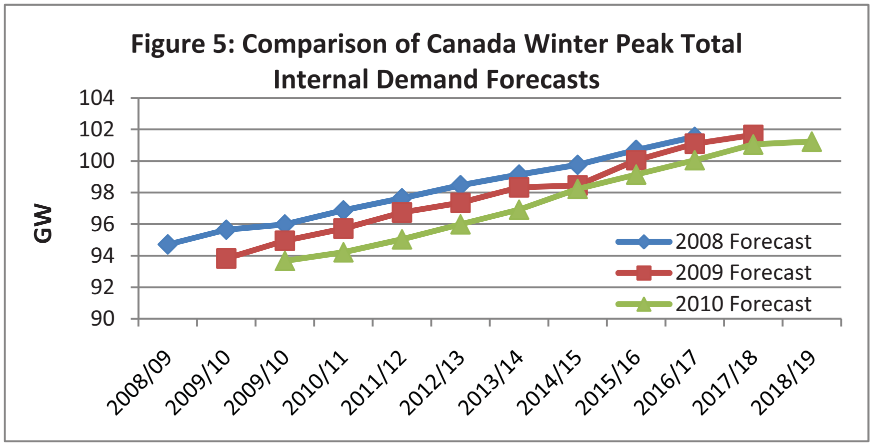
Figure 4: Comparative Annual Growth Rates Total US

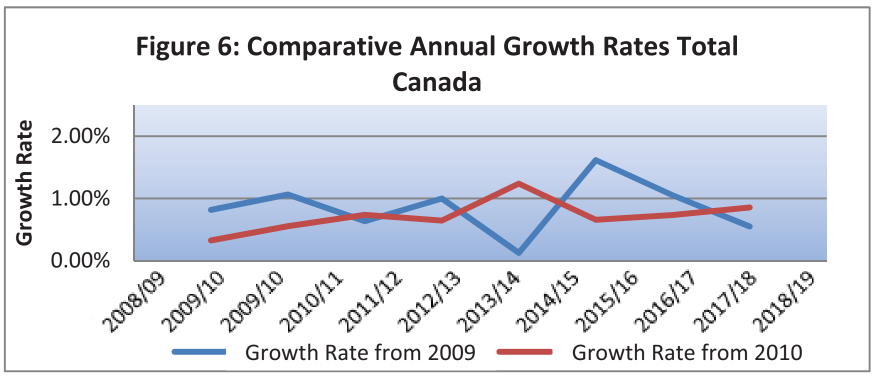


Total Internal Peak Demand in the United States is projected to grow at a rate of

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).





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
<u>United States</u>			
Summer Peak Demand (GW)	772	870	1.34%
Annual Net Energy For Load (TWh)	3,970	4,613	1.57%
<u>Canada</u>			
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.

[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

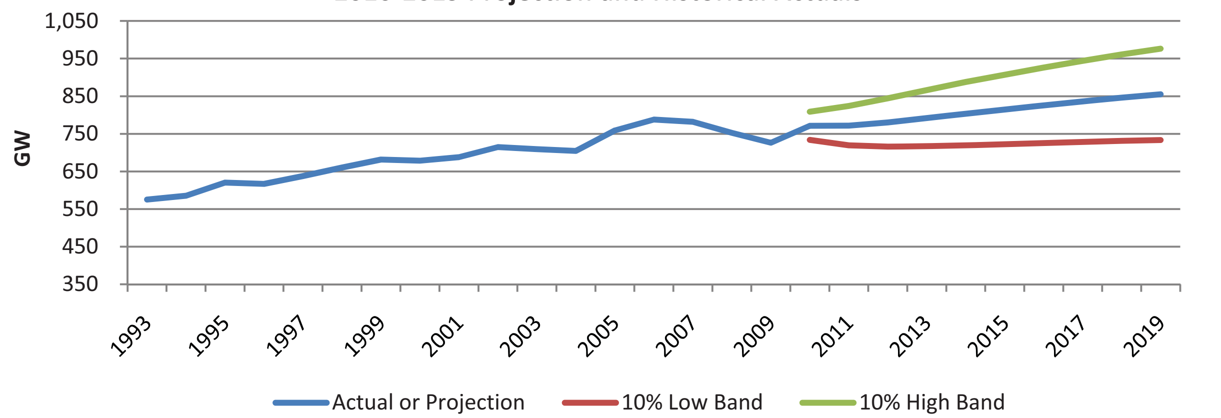
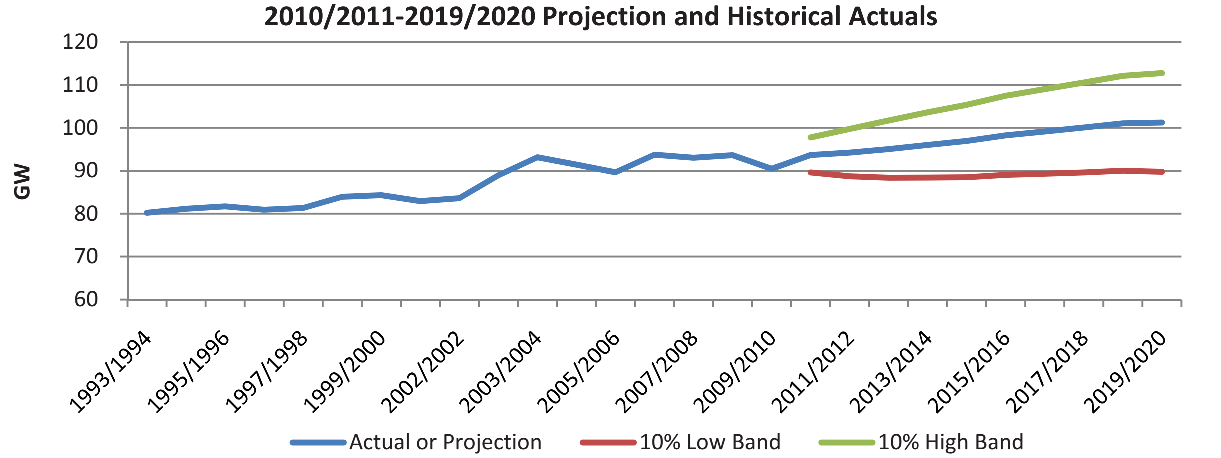


Figure 8: Canada Winter Peak Demand Forecast Uncertainty
2010/2011-2019/2020 Projection and Historical Actuals



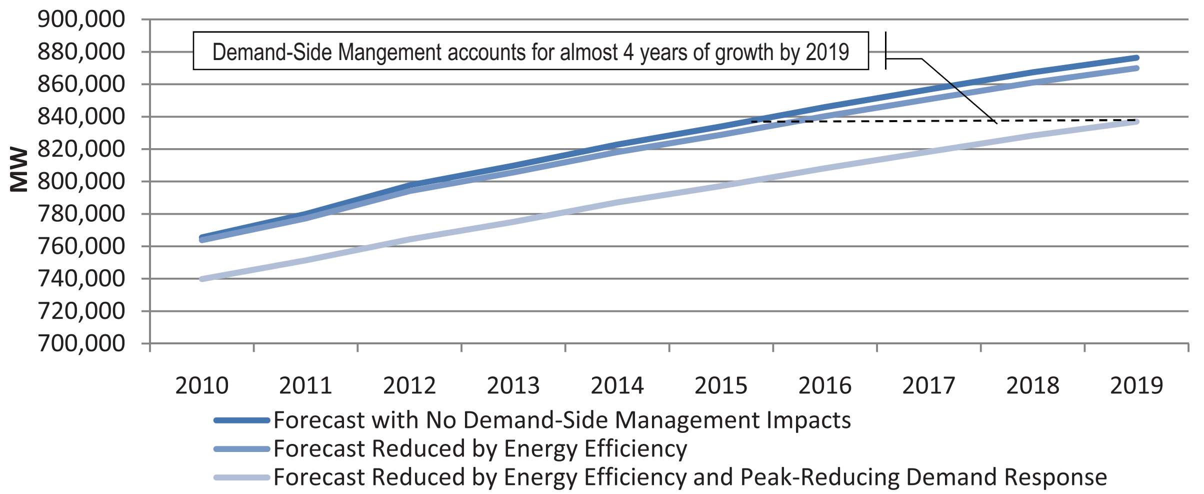
[8] Forecasts cannot precisely predict the future. Instead, many forecasts report a baseline or most likely outcome, and a range of possible outcomes based on probabilities around the baseline or midpoint. Actual demand may deviate from the midpoint projections due to VAriability in key factors that 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



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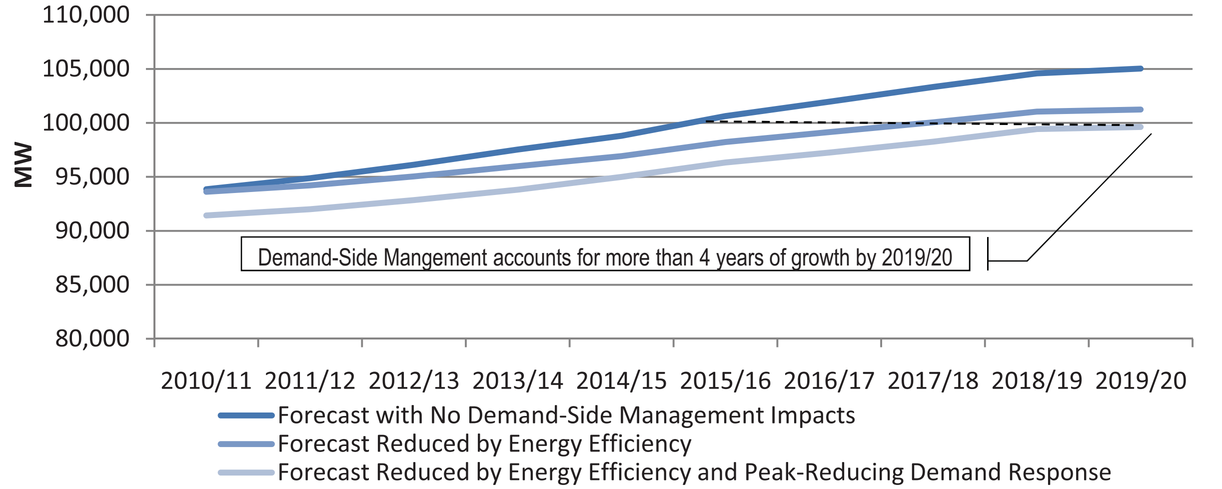
[9] NERC DADS is collecting Demand Response data on a semi-annual basis. The goal of the DADS is to collect Demand Response enrollment and event information to measure its actual performance including its contribution to improved reliability. Ultimately, this analysis can provide industry with a basis 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

Figure 10: Canada Winter Peak Demand Growth Reduced by Demand-Side Management



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.

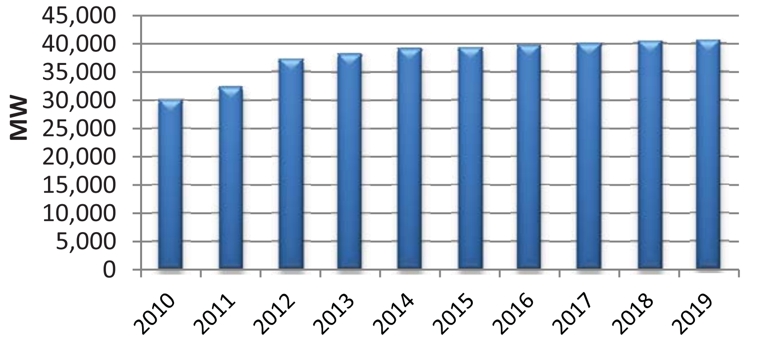
Potential drivers for the continued expansion of Energy Efficiency programs in the future are Renewable Portfolio Standards (RPS), which commonly include provisions for energy-reducing actions to account for

[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

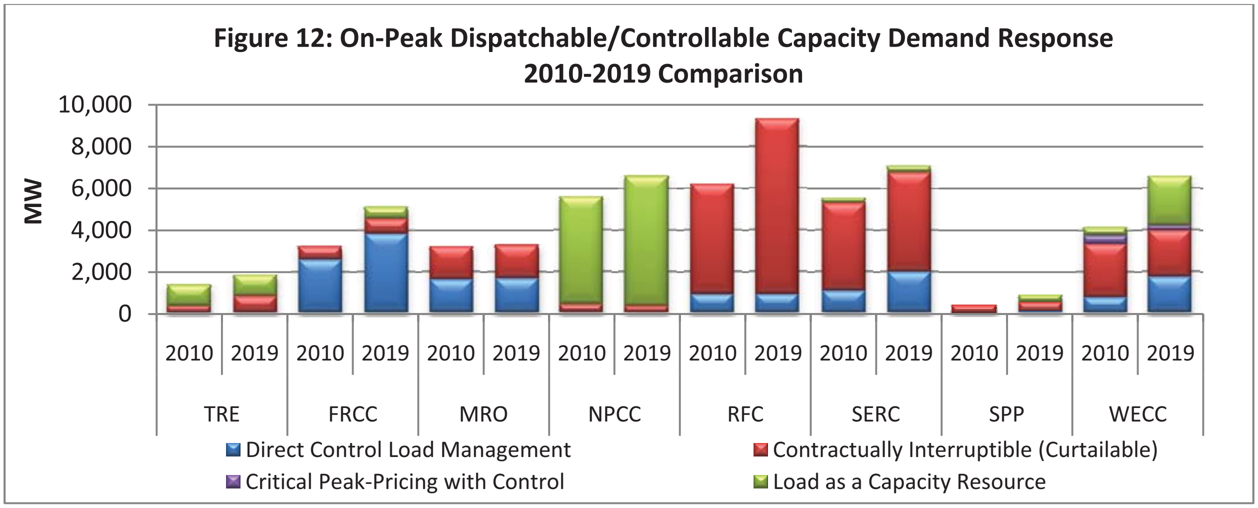
[12] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h2454pcs.txt.pdf

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

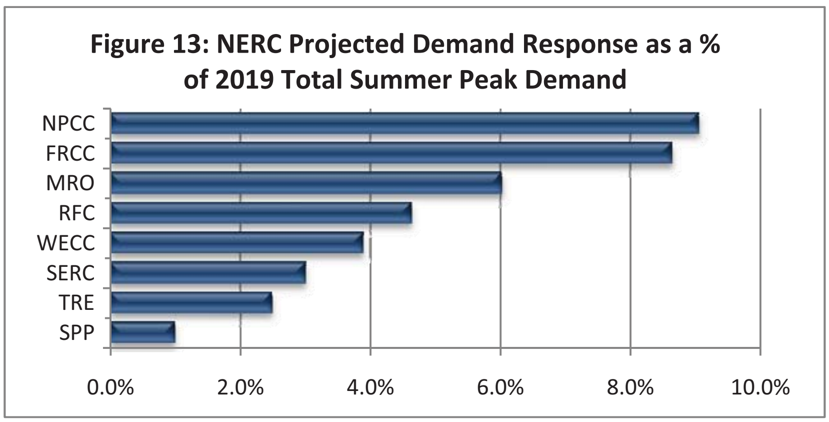
[14] Reliability Impacts of Climate Change Initiatives report: http://www.nerc.com/files/RICCI_2010.pdf

[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

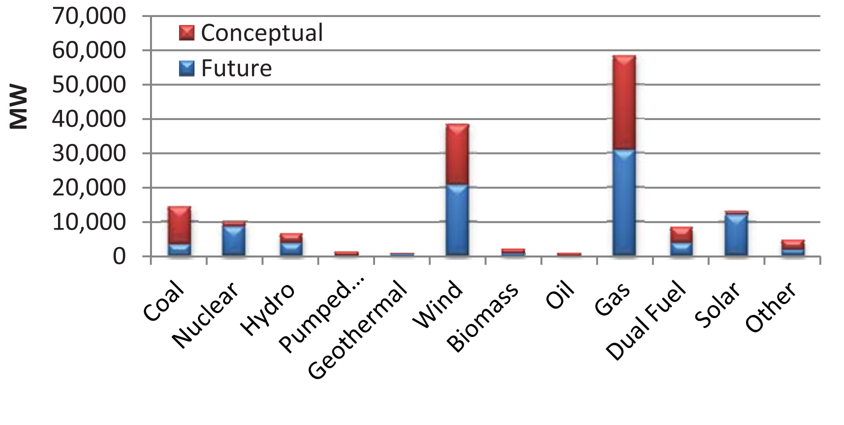
2010-2019 GENERATION PROJECTIONS

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]

Figure 14: Net Change in Expected Summer Peak Generation Capacity by 2019 by Fuel-Type



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.

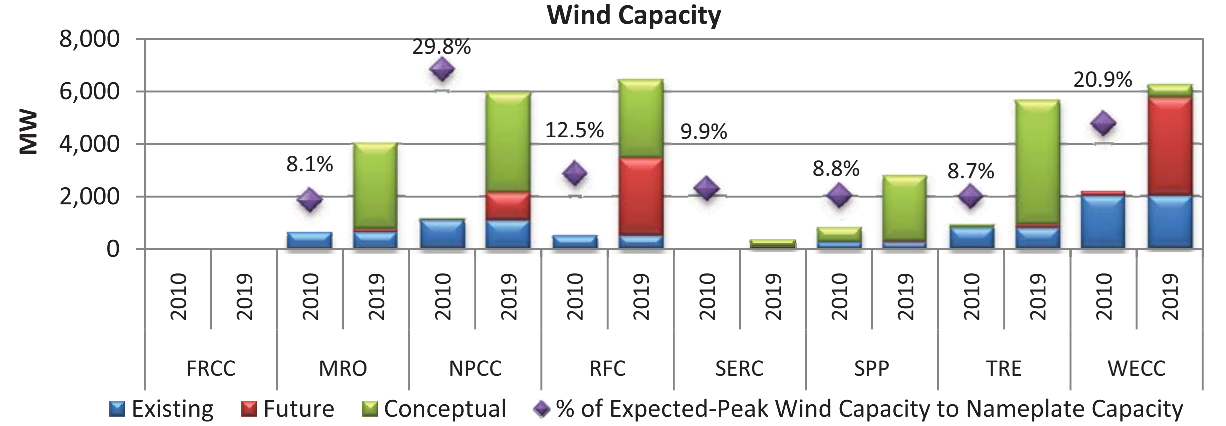
[19] Accommodating High Levels of Variable Generation: Summary Report: http://www.nerc.com/files/Special%20Report%20%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf

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

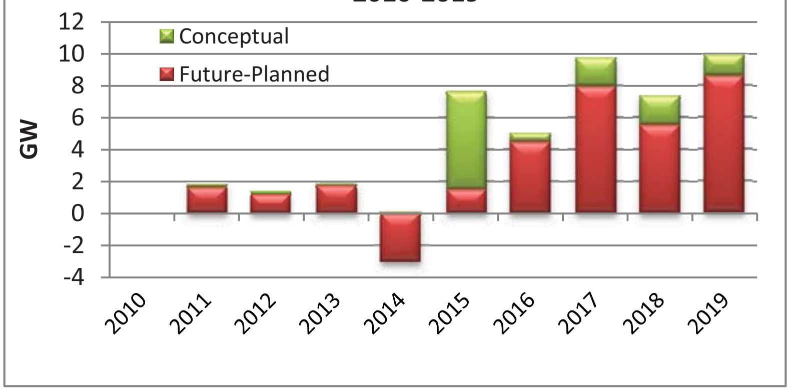
[22] Regional differences exist for calculating the expected on-peak capacity contributions of wind resources. http://www.nerc.com/docs/pc/ivgtf/IVGTF_Report_041609.pdf

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.

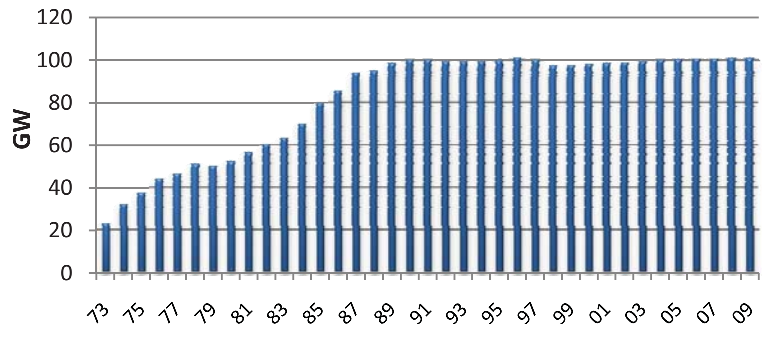
While gas-fired generation resources are projected to remain the largest fuel source used to meet demand on peak, a significant amount of new nuclear resources are also projected. The design specifications for these new nuclear units are large (over 1,600 MW) when compared to a single new gas-fired turbine 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.

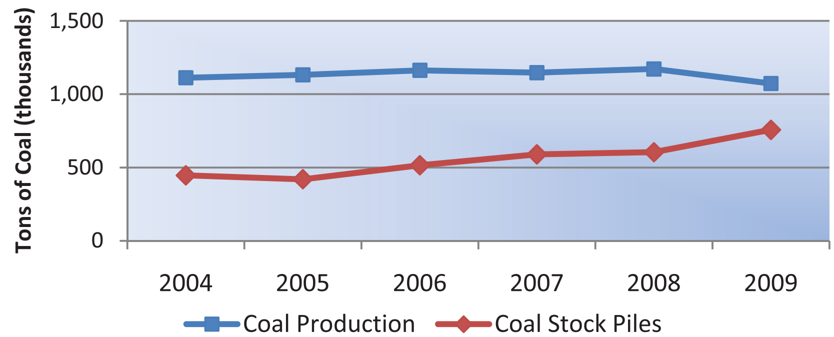
Coal Assessment

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.

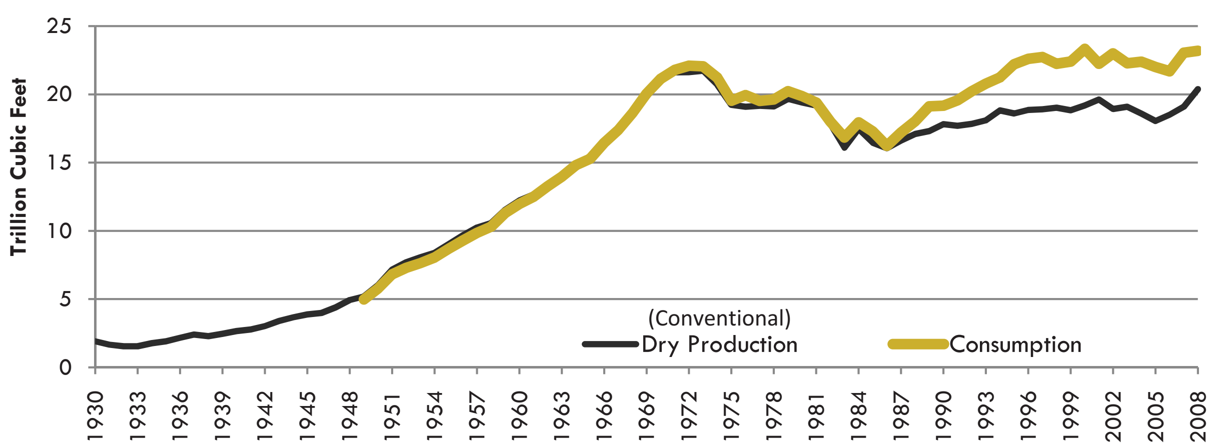
The precise annual growth rates of gas production from the newer unconventional basins (*e.g.*, shale gas), which are still in their infancy, are uncertain given the large amount of new drilling that is required to extract the gas. Successful development of unconventional gas is dependent on advanced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

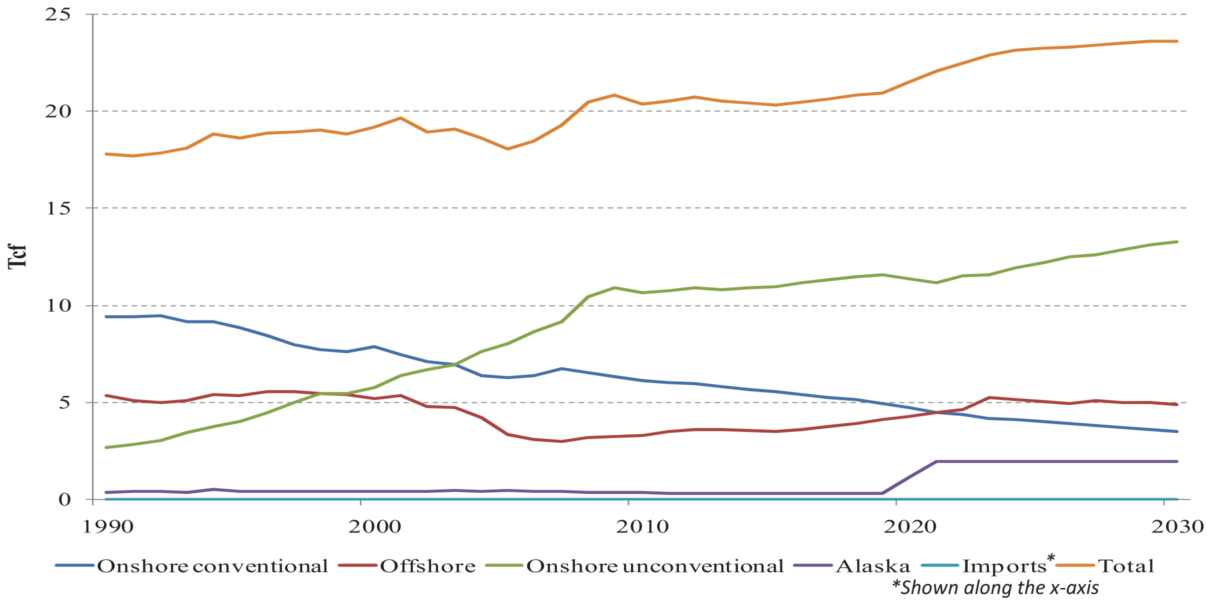
[30] *2010 Annual Energy Outlook: Natural Gas Demand* http://www.eia.doe.gov/oiaf/aeo/gas.html

[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.

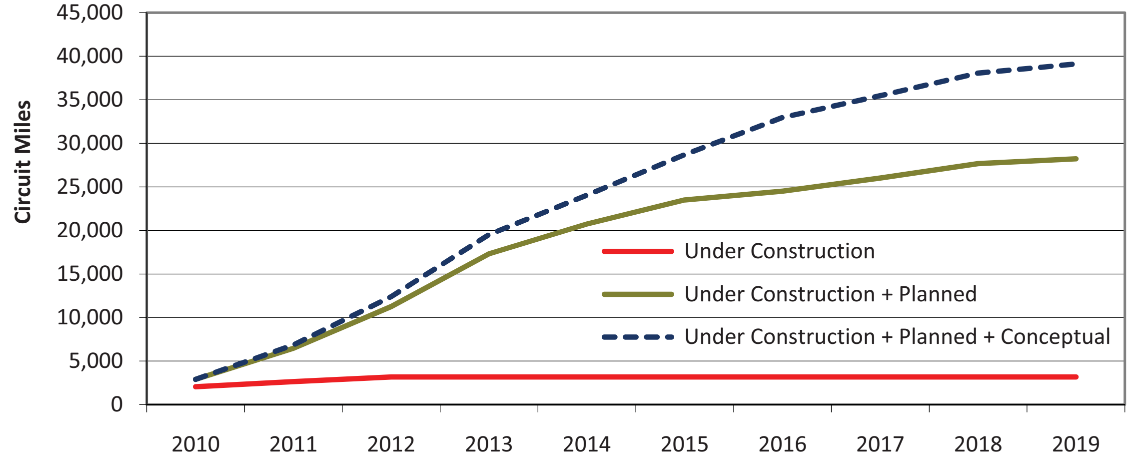
Table 3: Transmission Plans by Circuit Mile Additions > 100 kV

		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.

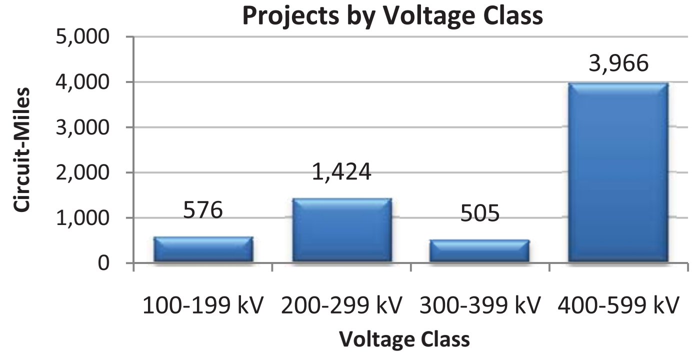
Figure 20: Transmission Line Additions > 100kV - Circuit Miles by Transmission Status



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.

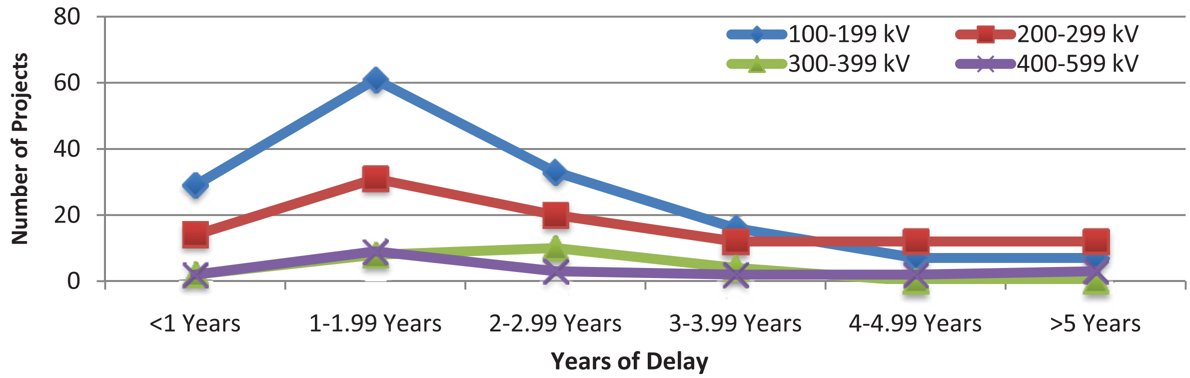
Figure 21: Mileage of Delayed Transmission Projects by Voltage Class



[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.

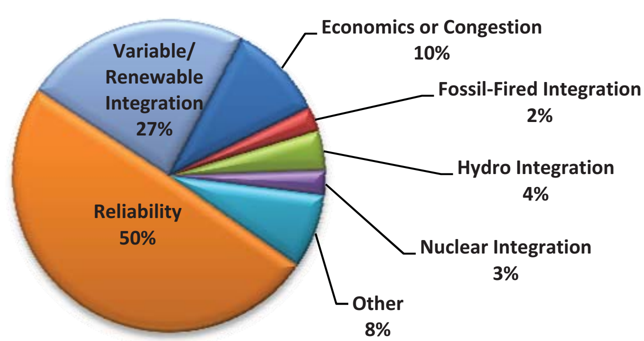
Over 120 projects between 100 and 199 kV are delayed up to three years as well. While longer, higher-voltage transmission lines are generally used to carry larger amounts of power great distances, lower-voltage transmission lines are critical to the operational reliability of a given system. These shorter, 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



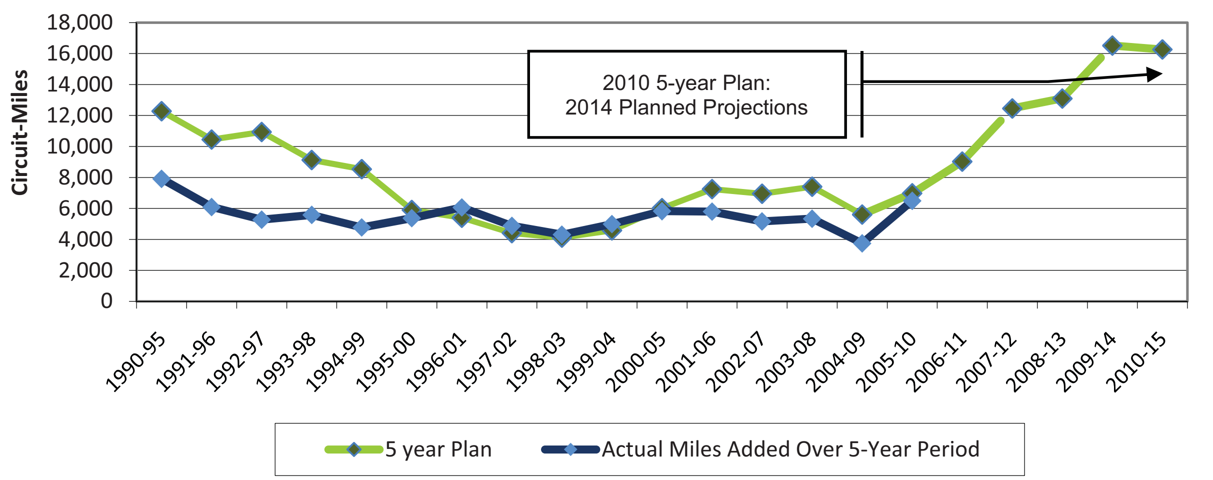
Along with the increased granularity on the status of transmission plans, NERC gathers information on key drivers of individual transmission line and infrastructure development projects. Bulk power system reliability and the integration of variable generation emerged as the predominant reason for the 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

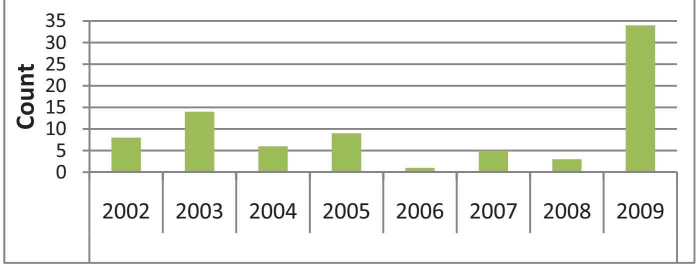
[36] See http://www.wecc.biz/index.php?module=pnForum&func=viewtopic&topic=909

[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.

Figure 25: SPP EEA3 Events



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.

[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.

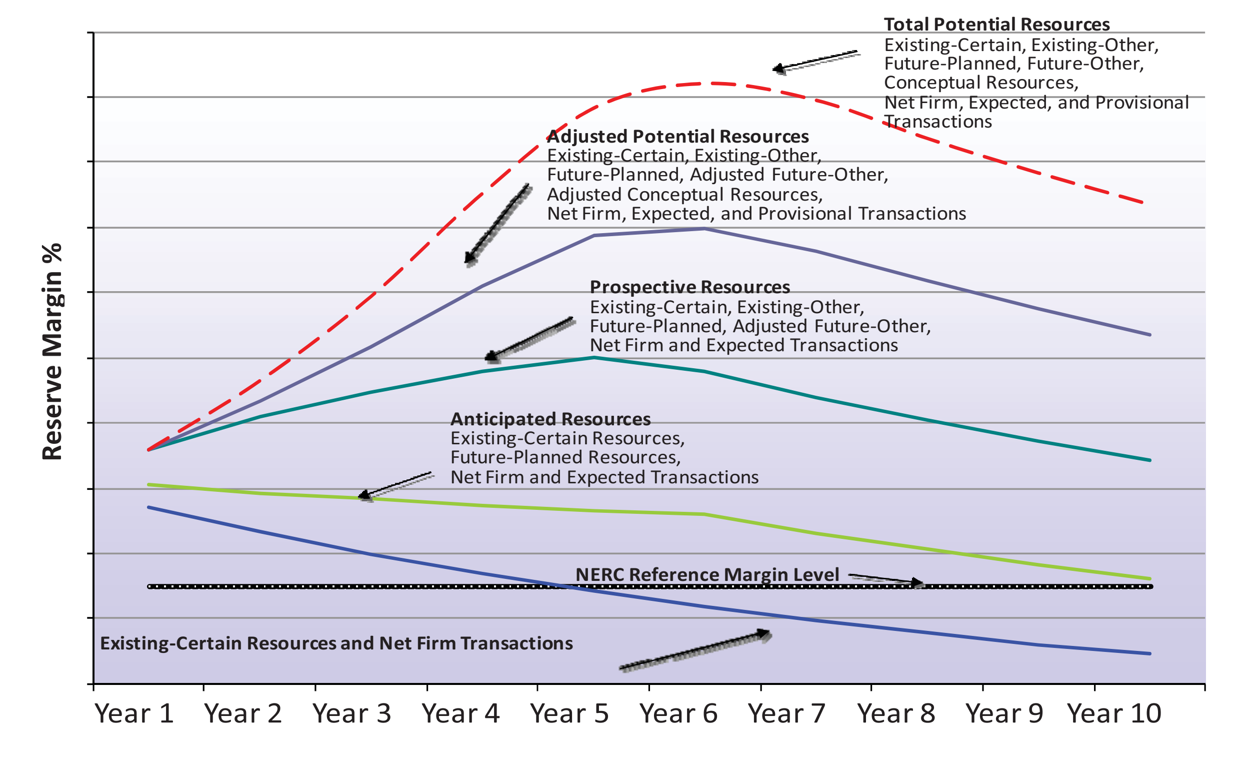
   b. **Future-Other** — Future generating resources that do not qualify in Future-Planned and are not included in the Conceptual category.

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]

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[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%

TEXAS INTERCONNECTION

TRE

EXECUTIVE SUMMARY

The unrestricted coincident long-term demand forecast for the TRE Region ranges from 64,052 MW in 2010 to 74,709 MW in 2019 and is lower in comparison to last year's forecast for each year of the forecast period due to the expected slower recovery from the economic recession. The 10th year peak Total Internal Demand is 74,467 MW and the 10th year peak Net Internal Demand is 72,791 MW. The TRE Region has 74,817 MW of Existing-Certain generation and approximately 8,895 MW Existing-Other generation, representing an increase of 2,965 MW of Existing-Certain since the 2009 LTRA. Future capacity that is expected to be available for the bulk of the assessment period includes 2,020 MW of gas fired generation, 1,944 MW from coal, 145 MW of biomass, and 1,326 MW nameplate capacity from wind turbines. TRE has an adequate reserve margin through 2014 but the reserve margin falls below the 12.5 percent minimum level used throughout the assessment period starting in 2015.

Approximately 110 miles of new or rebuilt 345kV transmission lines have been completed since the 2009 Long-Term System Assessment. A large number of transmission projects consisting of over 5,300 miles of new 345 kV lines will be coming into service within the next five years, primarily due to the inclusion of the new lines that have been ordered by the Public Utility Commission of Texas (PUCT) to complete its Competitive Renewable Energy Zones (CREZ) transmission plan. There are no known transmission constraints that appear to significantly impact reliability across the TRE Region.

Table TRE-1: TRE Regional Profile

	2010	2019
Total Internal Demand	63,810	74,467
Total Capacity	86,260	87,941
Capacity Additions	90	1,770
Demand Response	1,398	492

Wind generation is expected to result in congestion on multiple constraints until the new CREZ transmission lines are added between west Texas and the rest of the ERCOT system; these lines are currently scheduled to be completed by the end of 2013. From an operational perspective, the increasing reliance on wind generation in off-peak periods is expected to increase operating challenges. ERCOT ISO continues to develop protocols, tools and procedures to meet these challenges. For example, ERCOT ISO has developed a wind ramp forecasting tool to aid in the operation decisions used to prepare for periods of potential high wind variability and has modified the non-spin reserve procurement method specifically to address potential wind-ramp events identified in the day-ahead forecast.

The TRE Region has significant studies in progress looking at the reliability impacts of integrating variable resources. A voltage ride-through study, initiated in 2009 and due to be complete in 2010, is evaluating the capability of wind generation resources to stay on-line during voltage disturbances. The Region has also initiated an analysis to optimize the reactive capability necessary to support the CREZ facilities and the associated wind generation.

Introduction

The TRE Region is a separate electric interconnection located entirely in the state of Texas and operated as a single Balancing Authority and Reliability Coordinator area. The 10-year compounded annual growth rate for the system for 2010-2019 is 1.72 percent. TRE has an adequate reserve margin through 2014 but the reserve margin falls below the 12.5 percent minimum level used throughout the assessment period starting in 2015.

The TRE Region continues to make improvements regarding wind integration, including two new operational initiatives that include a modification to the non-spinning reserve method and a wind ramp-forecasting tool. A large number of new 345 kV transmission projects will be coming into service within the next five years, primarily to reduce congestion between west Texas wind generation and the rest of the ERCOT system. The TRE Region also has planning studies in progress to looking at the reliability impacts of integrating variable resources.

Demand

The 2010 long-term demand forecast for the TRE Region from 2010-2019 is lower in comparison to last year's forecast for 2009-2018 in each year of the forecast period. The reduction in the forecasted system peak demands is due to the slower-than-expected recovery of the economic recession, which is reflected in the economic assumptions upon which the forecast is based. The 10-year compounded annual growth rate for the system peak, from 2009-2018, in last year's forecast was 2.04 percent and the 10-year system peak growth rate for 2010-2019 in this year's forecast is 1.72 percent. The lower 10-year growth rate in this year's forecast is a result of more conservative assumptions due to the slow economic recovery.

The peak demand forecast for this summer peaking Region is based on the economic indicators that have been found to drive electricity usage in the TRE Region's eight weather zones. The economic factors which drive the 2010 ERCOT Long-Term Hourly Demand Forecast[203] include per capita income, population, gross domestic product (GDP), and various employment measures that include non-farm employment and total employment. The economic indicators and variables included in the ERCOT weather zone models are designed to reflect the impacts of the major drivers for peak demand and energy consumption.

The forecasted peak demands are produced by ERCOT ISO for the TRE Region, which is a single Balancing Authority area, based on the Region-wide actual demands. The actual demands used for forecasting purposes are coincident hourly values across the TRE Region. The data used in the forecast is differentiated by weather zones. The weather assumptions on which the forecasts are based represent an average weather profile (50/50). An average weather profile is calculated for each of the eight weather zones in TRE, which are used in developing the forecast. To assess the impact of weather

[203] http://www.ercot.com/content/news/presentations/2009/2009_ERCOT_Planning_Long-Term_Hourly_Demand_Energy_Forecast.pdf

variability on the peak demand for TRE, alternative weather scenarios are used to develop extreme weather load forecasts. One scenario is the one-in-ten-year occurrence of a weather event. This scenario is calculated using the 90th percentile of the temperatures in the database spanning the last fifteen years. These extreme temperatures are input into the load-shape and energy models to obtain the forecasts. The extreme temperature assumptions consistently produce demand forecasts that are approximately 5.0 percent higher than the forecasts based on the average weather profile (50/50). Together, the forecasts from these temperature scenarios are usually referred to as 90/10 scenario forecasts.

A 2007 Texas state law[204] mandated that at least 20 percent of an investor-owned utility's (IOU's) annual growth in electricity demand for residential and commercial customers shall, by December 31, 2009, be met through Energy Efficiency programs each year. The IOUs are required to administer energy savings incentive programs, which are implemented by retail electric and Energy Efficiency service providers. Some of these programs, offered by the utilities, are designed to produce system peak demand reductions and energy consumption savings and include the following: Commercial and Industrial, Residential and Small Commercial, Hard-to-Reach, Load Management, Energy Efficiency Improvement Programs, Low Income Weatherization, Energy Star (New Homes), Air Conditioning, Air Conditioning Distributor, Air Conditioning Installer Training, Retro-Commissioning, Multifamily Water & Space Heating, Texas SCORE/City Smart, Trees for Efficiency, and Third Party Contracts.

In general, utility savings, as measured and verified by an independent contractor, have exceeded the goals set by the utilities[205]. According to the latest assessment, utility programs implemented in 1999-2008 produced 1,125 MW of peak demand reduction and 3,014 GWh of annual electricity savings in the year 2008. Most of this demand reduction is accounted for within the load forecast and only the expected incremental portion for each year is included as a demand adjustment.

Loads acting as a Resource (LaaRs) providing Responsive Reserve Service provide an average of approximately 1,062 MW of dispatchable, contractually committed Demand Response during summer peak hours based on the most recently available data. LaaRs are considered an offset to peak demand and contribute to the reserve margin.

ERCOT's Emergency Interruptible Load Service (EILS) is designed to be deployed in the late stages of a grid emergency prior to shedding involuntary "firm" load, and represent contractually committed interruptible load. Based on past EILS commitments, approximately 336 MW of EILS load can be counted upon during the 2010 summer peak, increasing by 10 percent per year, for an expected 792 MW in 2019.

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[204] http://www.capitol.state.tx.us/tlodocs/80R/billtext/html/HB03693F.htm

[205] http://www.texasefficiency.com/report.html

GENERATION

The TRE Region has 74,817 MW of Existing-Certain generation, approximately 8,895 MW Existing-Other generation, and 2,449 MW Existing-Inoperable. In addition, the Region has 4,224 MW of Future, Planned capacity slated to go into service by 2014. Conceptual capacity ranges from 2,489 MW in 2011 to 5,317 MW in 2014.

TRE has existing wind generation nameplate capacity totaling 9,117 MW and that capacity is expected to increase to 10,443 MW by 2014; however, only 8.7 percent of the wind generation nameplate capacity is included in the Existing-Certain value used for margin calculations, based on a study of the effective load-carrying capability of wind generation in the Region. Consequently, the expected on-peak capacity of wind generation resources ranges from the current value of 793 MW to 908MW by 2014. The remaining existing wind capacity amount is included in the Existing-Other generation amount. Of the Existing-Certain amount, 91 MW is biomass, and 145 MW of additional biomass is included in the Future, Planned capacity.

Before a new power project is included in reserve margin calculations, a binding interconnection agreement must exist between the resource owner and the transmission service provider. Additionally, thermal units must have an air permit issued from the appropriate state and federal agencies specifying the conditions for operation. Future capacity that is expected to be available for the bulk of the assessment period includes 2,020 MW of gas fired generation, 1,944 MW from coal, 145 MW of biomass, and 1,326 MW nameplate capacity from wind turbines. Of the 1,326 MW of nameplate wind capacity, only 115 MW, or 8.7 percent, contribute to margin calculations. Conceptual capacity is comprised of projects that have progressed beyond feasibility studies and have secured a more substantial investment by the developer. Of the 53,989 MW in this Conceptual category, 4,762 MW can be attributed to wind capacity that counts toward the reserve margin, 29,544 MW is the de-rated portion of the installed nameplate capacity of the wind, 549 MW to solar, 50 MW to biomass, with the remaining 19,084 MW to conventional fuel sources. Historically, only twenty-two percent of projects in this category come to fruition. There is inadequate project history available to reasonably predict, by fuel type, the capacity that may eventually become operational.

CAPACITY TRANSACTIONS

ERCOT is a separate interconnection with only asynchronous ties to SPP and Mexico's Comisión Federal de Electricidad (CFE) and does not share reserves with other Regions. There are two asynchronous (DC) ties between TRE and SPP with a total of 820 MW of transfer capability and three asynchronous ties between TRE and Mexico with a total of 280 MW of transfer capability. TRE does not rely on external resources to meet demand under normal operating conditions; however, under emergency support agreements with CFE and with AEP (the Balancing Authority on the SPP side of the SPP DC ties), it may request external resources for emergency services over the asynchronous ties or through block load transfers.

For the assessment period, TRE has 458 MW of imports from SPP and 143 MW from CFE. Of the imports from SPP, 48 MW is tied to a long term contract for purchase of firm power from specific generation. The remaining imports of 410 MW from SPP and 143 MW from CFE represent one-half of the asynchronous tie transfer capability, included due to emergency support arrangements.

SPP members' ownership stakes of 247 MW of a power plant located in TRE results in an export from TRE to SPP of that amount.

There are no non-Firm contracts signed or pending over any of the ties. There are also no other known contracts under negotiation or under study using the asynchronous ties.

TRANSMISSION

The Public Utility Commission of Texas (PUCT) completed its Competitive Renewable Energy Zone (CREZ) transmission plan in 2008, resulting in bulk transmission in west Texas to provide solutions to existing and potential congestion and to enable the installation of more renewable generation in west Texas. The CREZ lines are expected to be in service by the end of 2013.

Several new 345kV lines are under construction. The Salado to Hutto portion of the Clear Springs/Zorn-Hutto-Salado project is expected to be in service before the summer peak in 2010. The Clear Springs/Zorn to Hutto portion is expected to be in service before the summer peak in 2011. A new line from San Miguel to Lobo (near Laredo) is expected to be in-service in 2010. There are also several additional new 345kV transmission lines expected to be in service by peak 2011. Several projects in the Dallas/Fort Worth, Corpus Christi, and San Antonio areas are planned to support reliability in these Regions. There are no known transmission constraints that would significantly affect reliability which are not addressed by these projects. 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.

Other significant substation equipment installed or planned for the TRE Region includes:

- Parkdale SVC, DFW Region
- Belair Thyristor Switched Capacitor, Houston Region
- Crosby Thyristor Switched Capacitor, Houston Region
- Holly Statcom, Central Texas

OPERATIONAL ISSUES

There are no known major facility outages, environmental restrictions or regulatory restrictions that could significantly impact reliable operations expected over the ten-year assessment period. The outage coordination process is designed and undertaken to address any reliability issues, as well as potential constraints, associated with planned outages due to transmission construction or maintenance. If constraints are identified, remedial action plans or mitigation plans are developed to provide for preemptive or planned responses to maintain reliability. Interregional transfer capabilities are not generally relied upon to maintain transmission reliability and address capacity shortages, although emergency support arrangements are in place, which provide for mutual support over the asynchronous ties or through block load transfers.

ERCOT maintains operating reserves of approximately 3 percent of peak, in addition to Regulation Service and Responsive Reserve Service. In the event that peak demands are expected to exceed all available generation and operating reserves, ERCOT will implement its Energy Emergency Alert plan (EEA), as described in Section 5.6.6.1 of the ERCOT Protocols[206] and Section 4.5 of the ERCOT Operating Guides[207]. The EEA plan includes procedures for use of interruptible load, voltage reductions, procuring emergency energy over the DC ties, and ISO-instructed demand reduction.

ERCOT has recently implemented two new operational initiatives that include a modification to the Non-Spinning Reserve method in order to assist in managing wind variability during off peak periods and a wind ramp-forecasting tool that provides a probabilistic assessment of the magnitude and likelihood of a significant change in aggregate wind output over upcoming operating periods. The Wind Ramp alert system is now in service and aids in operational decisions to prepare for periods that the wind may vary. The tool looks ahead 15 minutes, 60 minutes and 180 minutes and predicts the probability of ramp events. In addition, ERCOT evaluates the impact of increased installed wind generation on ancillary services requirements on an ongoing basis.

There are no anticipated reliability concerns resulting from high-levels of Demand Response resources. ERCOT limits the Demand Response participation of LaaRs at 50 percent of the hourly Responsive Reserve Service procurement, for which the minimum requirement is 2,300 MW. LaaRs are deployed automatically via UFR trip in response to frequency excursions below 59.7 Hz or through verbal dispatch during system emergencies such as Energy Emergency Alerts. There are no anticipated reliability concerns with distributed resource integration at this time.

RELIABILITY ASSESSMENT ANALYSIS

TRE has an adequate reserve margin from 2010 (20.5 percent) to 2014 (12.6 percent) but the reserve margin falls below the 12.5 percent minimum level used throughout the assessment period starting in 2015 (11.9 percent), based on new generation with signed interconnection agreements, expected mothballed resources, and existing resources (see Figure TRE-1). The minimum reserve margin target of 12.5 percent is applied to each year of the ten year assessment period and is based on a Loss-of-Load Expectation (LOLE) analysis[208], resulting in no more than one day in ten years loss of load.

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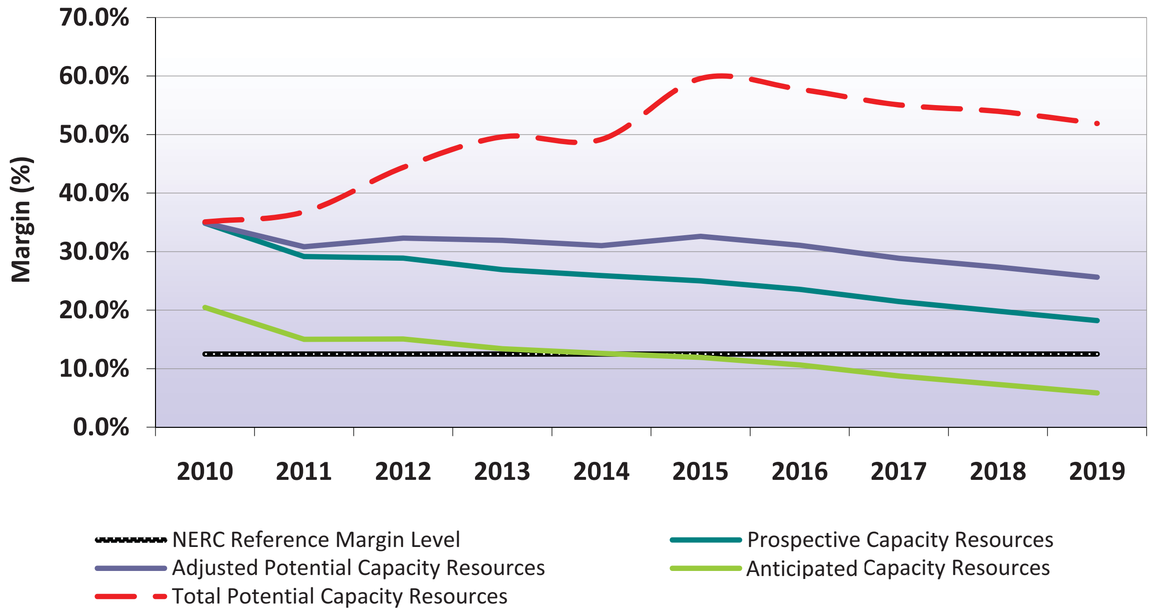
[206] http://www.ercot.com/mktrules/protocols/current.html

[207] http://www.ercot.com/mktrules/guides/operating/current

[208] http://www.ercot.com/meetings/gatf/keydocs/2007/20070112-GATF/ERCOT_Reserve_Margin_Analysis_Report.pdf

Figure TRE-1: Summer Peak Reserve Margin Projections



TRE relies almost entirely on internal resources to serve its load and reserves. TRE currently has 86,170 MW of installed capacity, with additional signed interconnection agreements for 5,435 MW of new generation capacity over the next ten years. In addition, 2,544 MW of existing resources are expected to be mothballed prior to 2011.

TRE has interconnections through DC ties with the Eastern Interconnect and with Mexico. The maximum imports/export over these ties is 1,106 MW. These ties can be operated at a maximum import and export provided there are no area transmission elements out of service. In the event of a transmission outage in the area of these ties, studies will be run during the outage coordination phase for the outages to identify any import/export limitations.

Reserve margins for the Region have decreased since last year's assessment due to the increase in expected mothballed resources (2,544 MW) and decrease in planned generation (1,792 MW) . This reduction in generation has offset the expected positive impact of lower forecasted demand and additional planned resources on the reserve margin.

With multiple sources of fuel supply, traditional fossil fuel interruptions are not expected to be an issue in TRE. In order to be prepared for an extended forced outage, generation deliverability studies are conducted by security constrained unit commitment and dispatch software that ensure enough generation is capable to meet non-coincident peak load post-contingency.

The Renewable Portfolio Standard for Texas (including areas of Texas that are outside the TRE Region) is 5,880 MW of installed renewable capacity by 2015 and 10,880 MW of installed capacity by 2025. Each entity that serves load is required to obtain new renewable energy capacity based on their market share of energy sales times the renewable capacity goal. The 2025 target has already been met.

Only 8.7 percent of existing wind generation nameplate capacity is counted on for Certain generation, based on an analysis of the effective load carrying capability of wind generation in the Region.[209] The remaining existing wind capacity amount is included in the Other generation amount. As solar continues to grow as a maturing resource in the ERCOT market, the effective load carrying capability of this resource will be studied.

The continued installation of new wind generation in west Texas is expected to result in congestion on multiple constraints within and out of west Texas for the next several years until new bulk transmission lines are added between west Texas and the rest of the ERCOT system. This is not expected to limit generation deliverability during peak periods, since only 8.7 percent of the installed wind capacity is counted for reserve purposes. The PUCT has ordered the construction of approximately $5 billion in transmission system upgrades as a part of the Competitive Renewable Energy Zone (CREZ) process[210]. This transmission is intended to enable wind generation in west Texas to be able to serve load in the rest of the TRE Region and is expected to be completed by the end of 2013.

Unlike many other ISOs and control areas, ERCOT ISO does not administer Demand Response products or services that are specifically designed for peak load reduction. ERCOT ISO's approach to Demand Response can be described as enabling load participation in Ancillary Services markets (particularly Responsive Reserves) and supplementing those Ancillary Services with short-term capacity based Demand Response that is subject to deploy during grid emergencies. In both cases, Demand Response resources are procured through market mechanisms and provide the service round the clock. ERCOT ensures that its Demand Response resources will perform as expected by monitoring online Ancillary Services capacity from load resources in real-time, conducting after-the-fact availability analyses, and conducting annual load-shed testing of Demand Response resources to ensure they are equipped with the necessary communications and curtailment equipment. No changes are anticipated to this approach at this time.

In the TRE Region, when a generation unit seeks to retire or mothball its facility, ERCOT protocols mandate a reliability study to ensure that the retirement or mothballing does not affect system reliability. If reliability is affected, transmission projects or mitigation plans are developed to mitigate the impact. Until such plans or projects can be completed, the unit may be contracted as a reliability must-run (RMR) unit to remain available for service. ERCOT currently has RMR agreements with two generators that were scheduled to retire but were determined to be needed to maintain transmission system reliability until an RMR Exit Strategy that relieves this need can be implemented.

The TRE Region currently has under-voltage load shed (UVLS) schemes established in the following areas: Houston (~5,100 MW), Dallas/ Fort Worth (~2,400 MW), Laredo (~160 MW) and the Rio Grande Valley (~340 MW). UVLS deployments are intended to provide a "safety net" in case other operating actions are not enough to resolve under voltage problems. UVLS are not generally relied upon to

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[209] http://www.ercot.com/meetings/gatf/keydocs/2007/20070112-GATF/ERCOT_Reserve_Margin_Analysis_Report.pdf

[210] Competitive Renewable Energy Zones Transmission Optimization Study, http://www.ercot.com/news/presentations/2008/index, p. 24ff

survive NERC Category B and C events, and system reinforcements may be made to limit the amount of load shed that is necessary under certain NERC Category D events. The Rio Grande Valley UVLS scheme is intended to prevent local voltage collapse that may result following certain Category C contingencies. ERCOT plans grid enhancements as needed in a continuous process and does not plan for additional UVLS schemes as a reliability tool.

There is no established planning process for catastrophic events. To the extent that ERCOT ISO is made aware of an impending crisis, the ERCOT ISO will take preventative measures as necessary, including ordering withdrawals of planned outages, ordering additional generation on-line, inquiring about extra assistance across the DC Ties, as well as performing special engineering studies to evaluate potential worst-case scenarios.

The TRE Region has significant studies in progress looking at the reliability impacts of integrating variable resources. A voltage ride-through study, initiated in 2009 and due to be complete in 2010, is evaluating the capability of wind generation resources to stay on-line during voltage disturbances. The Region has also initiated an analysis to optimize the reactive capability necessary to support the CREZ facilities with associated wind generation.

The Planning Authority and Transmission Planners (TP) in the Region participate in the planning process, including an annual ERCOT Five-Year Transmission Plan and the ERCOT Long Term System Assessment. In addition, each TP performs additional analysis of their portion of the ERCOT system as necessary. The ERCOT Five-Year Transmission Plan is performed to identify transmission system needs for years one through five and satisfies, in part, NERC TPL-001, TPL-002 and TPL-003 requirements. The 2009 Five-Year Transmission Plan analysis identified 41 reliability projects to be implemented between 2010 and 2014.

In the Planning horizon, the ERCOT Five-Year Transmission Plan study and additional voltage stability studies of future-year network conditions identify limiting elements under contingency. ERCOT ISO staff then propose projects to mitigate the problems as needed. In the Operating horizon, reactive margins are maintained in the major metropolitan areas. Areas of dynamic and static reactive power limitations are Corpus Christi, Houston, Dallas/Fort Worth, Rio Grande Valley, South to Houston generation, South to Houston load, North to Houston generation and North to Houston load. Operating Procedure Manual for the Transmission and Security Desk[211], Procedure 2.4.3, Voltage Security Assessment Tool, describes the procedure to monitor the system and to prevent voltage collapse using an online voltage stability analysis tool.

ERCOT plans for a 5 percent voltage stability margin for category B contingencies and a 2.5 percent margin for category C contingencies[212]. ERCOT planning criteria are intended to maintain sufficient dynamic reactive capability to maintain system voltages within the range for which generators are expected to remain online. Potential problems are reported to ERCOT System Planning and the affected

[211] http://www.ercot.com/mktrules/guides/procedures

[212] Section 5 of the ERCOT Operating Guides, http://www.ercot.com/mktrules/guides/operating/

TOs to develop corresponding transmission projects to resolve the lack of voltage stability margin and to TOPs for their re-assessment for the operating horizon.

No new special protection systems (SPS) or remedial action schemes were identified during the 2009 Five-Year Transmission Plan analysis.

Active power and reactive power flow-control devices, such as phase-shifting transformers, switchable series reactors and FACTS devices have been added to the ERCOT system to mitigate transmission constraints and improve system efficiency. In addition, ERCOT ISO staff and TRE stakeholders are evaluating and studying various new technologies that are expected to be deployed within the ERCOT system over the coming years with potential impacts on grid operations and reliability. These include synchrophasors to monitor the stress of the system; utility-scale batteries and other storage devices that are potentially capable of providing ancillary services; distributed generation deployed to provide backup power for severe weather events but also potentially available to help address electric grid capacity shortfalls; and plug-in electric vehicles with accompanying “smart charging” price offerings to encourage off-peak charging.

A major deployment of smart meters is underway by utilities in TRE that serve the competitive retail areas of the ERCOT system. By 2014, a total of more than 6 million advanced meters are expected to be deployed and operational. Customers at those meter sites will have their retail accounts settled at the ERCOT wholesale market level based on their 15-minute interval electricity usage. Smart meters in turn may lead to deployment of home area networks providing tools for these consumers to manage their electricity demand more efficiently. This combination of tools is expected to bring additional retail-level Demand Response to the TRE Region. While such Demand Response will not be dispatched by the ERCOT ISO, it is expected to have a currently positive impact on Regional load factors and peak load management.

REGION DESCRIPTION

The TRE Region is a separate electric interconnection located entirely in the state of Texas and operated as a single Balancing Authority and Reliability Coordinator area. The TRE Region is a summer-peaking Region with a population of about 22 million covering approximately 200,000 square miles. The TRE Region has 274 Registered Entities and encompasses about 85 percent of the electric load in Texas with an all-time peak demand of 63,400 MW set in July, 2009. TRE performs the Regional Entity functions described in the Energy Policy Act of 2005 for the TRE Region in which ERCOT operates.