NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2012 Summer Reliability Assessment

May 2012

RELIABILITY | ACCOUNTABILITY




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Preface and NERC Mission

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system of North America.[1,2] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, México.

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 seasonal 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.[3]

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

NERC assesses the reliability and adequacy of the North American bulk power system, which is divided into several assessment areas within and across the eight Regional Entity boundaries, as shown in the map and corresponding table above.[4] The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, México.

[1] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005: http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf

[2] The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[3] 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 bulk power system, 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 British Columbia, Ontario, New Brunswick, and Nova Scotia. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has 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 and enforceable in that jurisdiction.

[4] Assessment area boundaries are included in Appendix I of this assessment.

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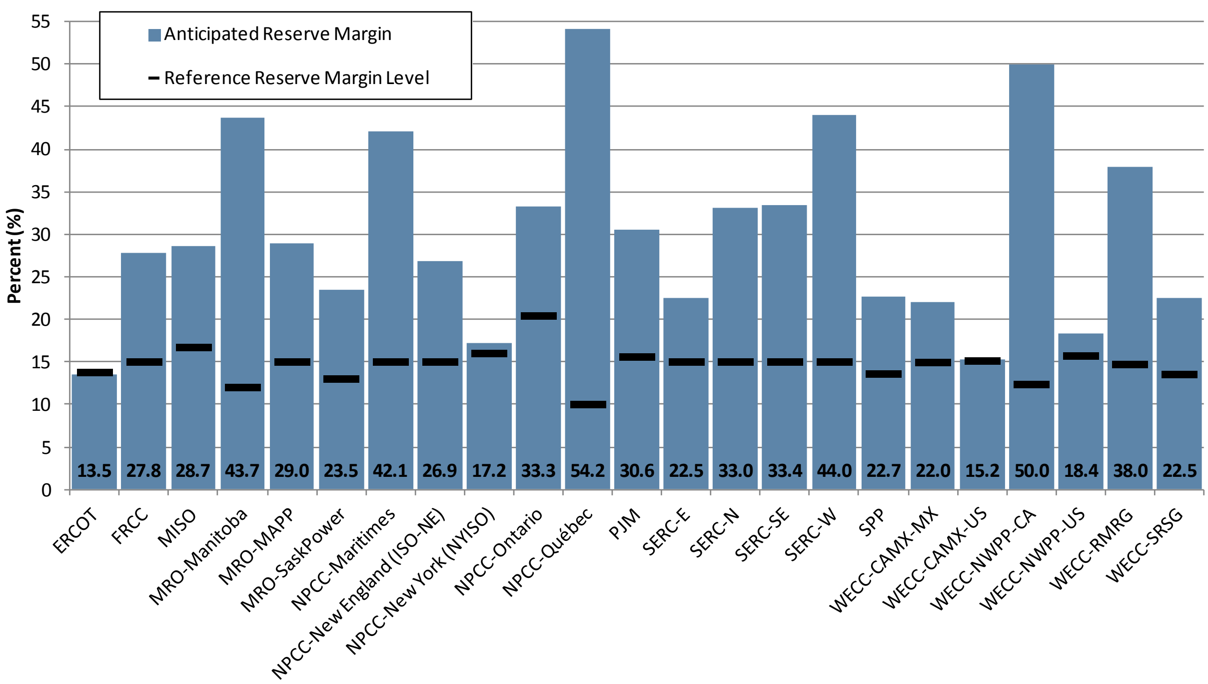
Executive Summary

2012 Summer Key Highlights

Extreme weather could lead to stressed conditions in Southern California and Texas; planned interruptions of firm load in Texas and Southern California may be necessary

For the 2012 summer operating period (June 1, 2012 through September 30, 2012), a majority of the assessment areas are projecting sufficient resources to meet summer peak demands. However, Planning Reserve Margins for ERCOT are below the Reference Margin Level. Figure 1 shows the reserve margins for the peak demand month (which varies for each assessment area) for the 2012 summer operating period. Insufficient reserves during peak hours could lead to an increased risk of entering emergency operating conditions, including the possibility of curtailment of interruptible loads and even rotating outages of firm loads.

Figure 1: Anticipated Reserve Margins for the 2012 Summer



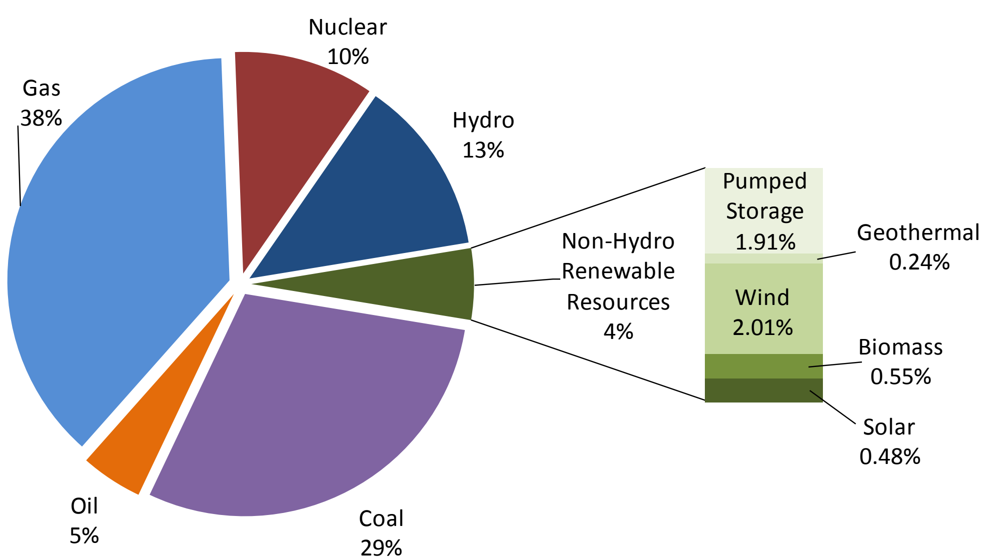
Since the summer of 2011, NERC-wide capacity resources have grown by approximately 12,310 MW. Capacity growth is projected in a number of assessment areas, including significant growth in SERC-W (4,410 MW growth, 12.7 percent increase), SERC-SE (3,320 MW growth, 5.4 percent increase), and NPCC-New England (2,227 MW growth, 7.5 percent increase). While PJM shows the largest absolute growth, the increase is primarily due to the integration of Duke Energy Ohio/Kentucky (DEOK). Figure 2 shows the change in summer capacity from the summer of 2011 to the summer of 2012.

Figure 2: 2011 and 2012 Net Change in Summer On-Peak Capacity[5,6]

	2011	2012	% Change	Capacity Decrease / Capacity Increase
PJM	180,406	185,424	2.78%	5,018
SERC-W	34,713	39,123	12.71%	4,410
SERC-SE	61,072	64,392	5.44%	3,320
NPCC-New England (ISO-NE)	29,590	31,781	7.40%	2,191
SPP	61,600	63,549	3.17%	1,950
WECC-Total	173,687	175,228	0.89%	1,541
SERC-N	57,632	59,106	2.56%	1,474
NPCC-Québec	33,222	33,907	2.06%	685
MRO-MAPP	7,078	7,321	3.43%	243
MRO-SaskPower	29,821	29,875	0.18%	14
MRO-Manitoba	3,632	3,647	0.39%	7
ERCOT	5,364	5,371	0.13%	-10
MISO	73,080	73,070	-0.01%	-164
SERC-E	107,391	107,227	-0.15%	-675
NPCC-Ontario	29,821	29,125	-2.33%	-696
NPCC-Maritimes	5,853	4,599	-21.42%	-1,254
NPCC-New York (NYISO)	36,700	34,908	-4.88%	-1,792
FRCC	55,775	52,351	-6.14%	-3,424

NERC-wide on-peak capacity projections for the 2012 summer do not change significantly, compared to the summer of 2011 projections. Gas-fired generation continues to be the dominant on-peak fuel source during periods of peak, followed by nuclear and coal generation to cover base load. Figure 3 includes the projected NERC-wide on-peak capacity mix for the 2012 summer.

Figure 3: 2012 Summer On-Peak Capacity Mix[7]



5 Capacity values include Existing-Certain and Future-Planned capacity for the summer peak month.

6 Duke Energy Ohio/Kentucky (DEOK) exited from MISO and integrated into the PJM RTO on January 1, 2012. This accounts for a 5 GW shift in capacity. WECC subregional boundary changes in 2012 have also distorted direct subregional comparisons.

7 Data presented in this chart is based on the data collected for the *2011 Long-Term Reliability Assessment* capacity forecasts (Schedule 9A and 9B).

For the 2012 summer, NERC is forecasting a reduction in Total Internal Demand of approximately 3,700 MW (or 0.4 percent). While some areas are forecasting modest growth in demand, most areas are projecting either a reduction or flat growth in peak demand when compared to the 2011 summer. ERCOT and New York (the NPCC-NYISO assessment area) show the largest percentage growth, with each area forecasting approximately 1.7 percent of increased peak demand. Conversely, the SERC-N, and MRO-MAPP (primarily North Dakota, South Dakota, and Minnesota) show the largest relative decrease in peak demand compared to last year – approximately 5.7 percent. SERC-N also shows the largest absolute reduction since last year. Figure 4 includes the 2011 forecasted and actual Total Internal Demand versus the 2012 summer forecast.

Figure 4: 2011 and 2012 Summer Total Internal Demand[8]

	2011 Forecast	2011 Actual	2012 Forecast	Forecast % Change	Demand Decrease / Demand Increase
ERCOT	64,964	68,416	66,076	1.71%	1,112
NPCC-New York (NYISO)	32,712	33,865	33,295	1.78%	583
SPP	53,512	55,352	54,051	1.01%	539
SERC-W	25,101	25,585	25,403	1.20%	302
WECC-Total	149,148	147,299	149,173	0.02%	25
SERC-E	43,249	43,253	43,255	0.01%	6
MRO-SaskPower	3,045	2,988	3,044	-0.05%	-1
MRO-Manitoba	3,166	3,378	3,143	-0.73%	-23
NPCC-Ontario	23,561	25,450	23,409	-0.65%	-152
NPCC-Maritimes	3,553	3,329	3,392	-4.53%	-161
MRO-MAPP	5,087	4,732	4,799	-5.67%	-288
NPCC-Québec	21,283	21,354	20,988	-1.39%	-295
SERC-SE	49,314	50,309	48,895	-0.85%	-419
FRCC	46,091	44,798	45,613	-1.04%	-478
NPCC-New England (ISO-NE)	27,550	33,865	26,462	-3.95%	-1,088
PJM & MISO	248,513	257,135	246,884	-0.66%	-1,629
SERC-N	46,846	45,579	45,102	-3.72%	-1,744

The unanticipated outage of the San Onofre Nuclear Generating Station (SONGS) reduces available summer capacity; transmission ties critical to reliability of Southern California

In California (the WECC-CAMX-US assessment area), Planning Reserve Margins are above the NERC Reference Margin Level for the upcoming summer. The Anticipated Reserve Margin for WECC-CA-MX for the peak month of July is 15.2 percent, 0.1 percent above the area's target level (15.1 percent).The San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 – a total of 2,150 MW – will remain out of service throughout the summer due to premature wear in the steam tubes of these units. The unavailability of this plant and a continuation of drought conditions accompanied with a stretch of higher-than-average temperatures or significant generation or transmission outages, could result in the deployment of load

[8] With Duke Energy Ohio/Kentucky (DEOK) exiting MISO and integrating into the PJM RTO on January 1, 2012, NERC has combined the demand projections from both assessment areas to provide comparable forecasts between 2011 to 2012. WECC subregional boundary changes in 2012 have also distorted direct subregional comparisons to 2011 projections.

shedding procedures in the San Diego and Los Angeles Basins to maintain the reliability of the bulk ower system.

Although ERCOT and the California Independent System Operator (CAISO) have worked diligently to mitigate reliability risks for this summer, maintaining sufficient operating reserves will likely remain a challenge, especially if extreme weather is experienced. Both areas have instituted procedures for bringing mothballed units back into service, accelerating the completion of needed transmission projects, and establishing customer agreements to provide more peak reduction capability. In California, with 14,000 MW of expected import transfers from neighboring areas, increased reliance on transmission ties to import the required power could further stress the system. At the time of this report's publication, system planners and operators continue preparation efforts as well as the development of operating procedures to manage extreme conditions that can further stress the bulk power system.

Enhanced operations and planning approaches instituted in response to 2011 southwest outage

The September 8, 2011 event stemmed primarily from weaknesses in two areas: operations planning and real-time situational awareness. These same weaknesses were identified in the August 2003 blackout that affected an estimated 50 million people in the northeastern United States and Canada. Without adequate operations studies and situational awareness, entities responsible for operating and overseeing the transmission system could not ensure reliable operations within System Operating Limits (SOLs) or prevent cascading outages in the event of a single contingency, such as the loss of a single transmission line.

To improve situational awareness in the WECC Region, recommendations were made to: (1) expand entities' external visibility in their models through, for example, improved data sharing and expanded use of Inter-Control Center Communications Protocol (ICCP) data links or similar technology; (2) improve the use of real-time tools to ensure the constant monitoring of potential contingencies; and (3) improve communications between entities to help maintain situational awareness.

Variable generation continues to increase in most assessment areas

Variable generation continues to increase in most assessment areas. Specifically, MISO and New England have reported significant increases in nameplate wind capacity for the 2012 summer operating period. A total of 4,576 MW of nameplate wind generation has been installed since last year, reflecting a modest increase of 1,880 MW of expected capacity on-peak. Solar and other renewables have not significantly increased since last summer, but are expected to in the longer term. Additional information on this issue will be provided in the NERC *2012 Long-Term Reliability Assessment*.

Operationally, an increase in wind resources continues to challenge operators with the inherent swings, or ramps, in power output. In certain areas, where large concentrations of wind resources have been added, system planners must accommodate added variability by increasing the amount of available regulating reserves, and potentially carrying additional operating reserves.

Demand-side management key in maintaining reliability this summer

Demand-side management programs, which include conservation, energy efficiency, and a variety of demand response programs, provide the electric power industry the ability to reduce peak demand and to potentially defer the need for some future generation capacity. With tight margins in some areas, successful deployment of demand response will be critical for maintaining reliability this summer. Depending on summer conditions, demand response may be used more often this summer in areas with tight margins, such as Texas and Southern California.

Extreme weather events will challenge bulk power system operators

Operational issues may challenge the industry during the upcoming summer, which would require increased flexibility to manage reliability impacts, such as weather (extended periods of high temperatures), long-term unavailability of generation, drought, and environmental restrictions (for cooling water). Many of these issues reflect the operating conditions expected in Texas. While drought conditions have improved since last year, persistent effects are expected through the summer. Tight reserve margins will impact the ERCOT system operator's flexibility to deal with unexpected or more extreme situations (*i.e.*, significant generator outages and/or higher than expected demand).

Lower global LNG supply may impact LNG-dependent generation in New England; ISO to implement proactive measures

NERC does not expect any significant fuel supply or delivery issues for the summer months. However, foreign supply-chain issues could reduce the amount of LNG shipped into New England this summer. ISO-NE is currently developing procedures to ensure plants operate during peak periods.

Fuel supply constraints in all other areas are less likely due to ample on-site coal inventories and sufficient natural gas supplies, including unprecedented storage spurred by an increase in shale production and a mild winter. While natural gas transportation issues remain a concern, given the increase in gas-fired generation and associated interdependency issues, these risks are generally more prominent during the winter seasons when gas pipeline and electric system can peak at the same time.

Environmental Regulations not expected to impact reliability in the short-term

Forthcoming environmental regulations continue to be evaluated in planning processes across the United States. Remaining uncertainties about unit retirements, Section 316(b), and retrofit and maintenance schedules are being assessed for long-term planning. However, for this summer, no impact is expected from any of the pending and/or final environmental rules. While some generator retirements have already been announced, all retirements have been accounted for and included in this assessment. Additionally, there is little uncertainty that generators would retire or derate between the time of this publication and the summer peak. Because of the longer-term reliability risks associated with the electric industry's response to comply with environmental regulations, NERC will continue to monitor industry progress and report on developing issues in the *2012 Long-Term Reliability Assessment*.

Top Reliability Issues for Summer 2012

To maintain reliability, planned interruptions to Firm load may be necessary in Texas

During the 2012 summer operating period, the ERCOT Independent System Operator (ISO)[9] is expecting the assessment area to be below the Reference Margin Level in August 2012. Specifically, an Anticipated Reserve Margin of 13.51 percent is below the ERCOT criteria of 13.75 percent. With the ERCOT ISO reserve margin below the NERC Reference Margin Level, ERCOT does not appear to have sufficient resources to maintain required resource adequacy levels. This may result in an increased probability of interruptions of firm load to maintain reliability.

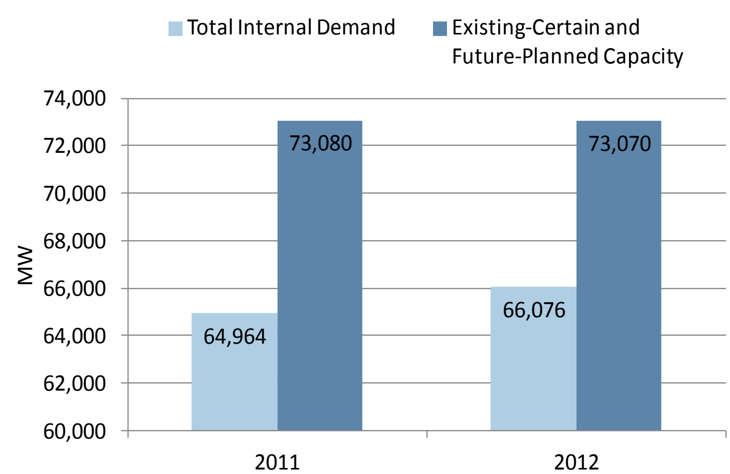
1,100 MW
increase in peak demand

10 MW
reduced capacity

since last summer

The projected summer peak Total Internal Demand in ERCOT is 66,076 MW, which will occur in August. The 2012 summer forecast is 2,340 MW less than the all-time record-peak demand of 68,416 MW[10] in ERCOT, which occurred last year on August 3, 2011 during extreme weather conditions which were experienced throughout the southern United States. With 73,070 MW of projected capacity resources, reserve capacity needed to accommodate unplanned forced outages and load forecast deviations diminishes to less than 7,000 MW, as shown in Figure 5.

Figure 5: 2011 and 2012 ERCOT Demand and Capacity Forecast



If ERCOT incurs an above average number of generation outages or experiences record-breaking electricity demand due to the onset of extreme temperatures again this summer, ERCOT may need to initiate rotating outages to maintain the reliability of the interconnection.[11]

During the 2011 summer peak, approximately 4,000 MW of generation was unexpectedly forced out of service. Additionally, the actual peak demand experienced in August was approximately 3,500 MW above the projected Total Internal Demand. During the onset of extreme August temperatures, ERCOT implemented emergency procedures on six days, due to low operating reserve capacity. Demand conservation that was practiced by consumers and businesses, coupled with non-Firm load-shed, helped to alleviate the need for ERCOT

[9] The Electric Reliability Council of Texas (ERCOT) is the Independent System Operator for the ERCOT Interconnection and schedules power on an electric grid that connects 40,500 miles of transmission lines and more than 550 generation units. Texas Reliability Entity (TRE) is the Regional Entity responsible for assessing the reliability of the bulk power system within ERCOT.

[10] ERCOT 15 minute demand value; the 2012 forecast is 2,340 MW less than the all-time peak experienced during the 2011 summer.

[11] Interruption of Firm load and rotating outages are tools that system operator can deploy to maintain the stability of the bulk power system and avoid uncontrolled, cascading outages of large areas.

system operators to initiate rotating outages of Firm load. Should similar conditions occur this summer, little flexibility will be available to system operators and maintaining reliability could be a significant challenge.

In advance of the summer operating period, ERCOT and generation capacity owners in Texas have taken a number of actions to enhance resource adequacy to ensure the reliable operation of the ERCOT Interconnection.

Actions taken by ERCOT included approving the Nodal Protocol Revision Requests (NPRR) to enhance resource adequacy for the summer operating period. NPRR outlines the procedures and processes used by ERCOT and market participants for the orderly functioning of the ERCOT system and nodal market. The two NPRRs approved during the April 2012 ERCOT Board of Directors meeting to enhance reliable operations for the 2012 summer operating period, are as follows:

- NPRR450 – Revise Requirements for Contracts to Procure Additional Capacity to Alleviate Emergency Conditions (Effective: 5/1/2012). This action authorizes ERCOT to contract for generation and load resources to address emergency conditions and to notify the ERCOT Board of such actions at its next meeting.[12]
- NPRR 451 – Implementation of new Texas Public Utility Commission (PUC) Substantive Rule §25.507. This action includes distributed generation among the emergency response resources ERCOT may call upon to help stabilize the grid during emergencies.[13]

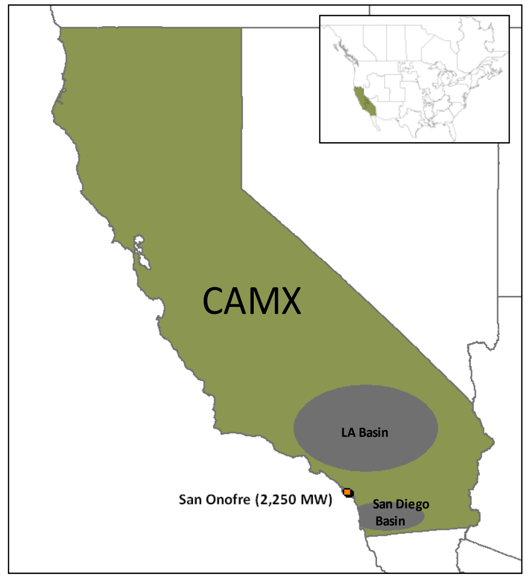
ERCOT has also announced that an additional 2,000 MW of capacity that had been mothballed or taken off-line for an indefinite period of time, will be back into service for the 2012 summer operating period.[14] This 2,000 MW of nameplate capacity (1,567 MW on-peak) includes approximately 430 MW of capacity that was not available during the 2011 summer operating period. These capacity enhancements increase the likelihood of ERCOT mitigating capacity reserve shortage for the 2012 summer without large scale system operator intervention to maintain reliability. However, these preparations have not yet increased the reserve capacity to a sufficient level. ERCOT's resource adequacy from 2013 through 2022 will be examined in greater depth in NERC's *2012 Long-Term Reliability Assessment*, expected to be published in November 2012.

[12] NPRR450 authorized ERCOT to contract for generation and load resources to address emergency conditions. http://www.ercot.com/mktrules/issues/nprr/426-450/450/index

[13] NPRR451 also changes the name of ERCOT's Emergency Interruptible Load Service (EILS) to Emergency Response Service (ERS) to reflect recent PUC rulemaking (Substantive Rule 25.507), which seeks to improve reliability by offering ERCOT a more diverse set of tools to help prevent rotating outages or a potential blackout. http://www.ercot.com/mktrules/issues/nprr/451-475/451/index

[14] The 2,000 MW of returned mothballed generation is included in the reported available capacity (Existing-Certain) of 73,070 MW.

The unanticipated outage of the San Onofre Nuclear Generating Station (SONGS) reduces available summer capacity; transmission ties critical to reliability of Southern California



On January 31, 2012, San Onofre Nuclear Generating Station (SONGS) Unit 3 was shut down due to indications of a leak in a steam generator tube. Subsequent inspections of steam generator tubes confirmed that there was a small leak on a single tube in one of the two steam generators. Continuing inspections of 100 percent of the steam generator tubes in both Unit 2 and Unit 3 steam generators identified 10 total steam generator tubes with reduced tube wall thicknesses from 90 to 28 percent of normal, which was classified as unexpected wear of tubes. As a precautionary measure, both Unit 2 and Unit 3 were taken offline to further investigate and resolve the identified problem. Progress is being monitored by federal, state, and local authorities, which includes staff from the US Nuclear Regulatory Commission and the California Energy Commission.

Technical studies conducted by the California Independent System Operator (CAISO) for the WECC-CAMX-US assessment area show tight reserve margins for San Diego and the Los Angeles Basin load center areas, especially during potential summer heat waves. Planning Reserve Margins are forecast to be approximately 0.1 percent above the NERC Reference Margin Level of 15.1 percent during the peak demand period of July 2012.[15]

15.2%
WECC-CAMX-US Anticipated Reserve Margin

Contingency planning in CAISO includes the following mitigation strategies (as of publishing):

- Calling back into service the Huntington Beach Power Plant, previously slated for retirement. This not only adds 452 MW of capacity in the Los Angeles Basin, but will also enable 350 MW of additional imported power to transfer into the San Diego metropolitan area.
- Accelerating the completion of Barre-Ellis and Sunrise Powerlink transmission projects.
- Re-activating the 20/20 demand reduction program, Flex Alert TV and radio conservation campaign.
- Coordinating military and public agency conservation in key areas of Southern California to further reduce peak demand

In addition to conservation and demand response programs developed for specific local areas to mitigate the SONGS outage, CAISO will be able to tap about 2,296 MW of demand response and interruptible load programs to provide operational flexibility during periods of stress on the grid. Figure 6 shows the 2012 transmission enhancements in Southern California, while Figure 7 shows CAISO preparations to deal with the capacity shortage caused by the SONGS outage.

[15] This includes the scheduled outage of SONGS Units 2 and 3 (2,200 MW).

Figure 6: 2012 CAMX-US Transmission Enhancements

The addition of 926 MW of generation capacity – half of which is renewable generation capacity – is projected between the summer of 2011, through the end of the 2012 summer operating period (September 30, 2012).

At the time of publication, the latest estimate for the return to service of SONGS (in filings to the U.S. Nuclear Regulatory Commission) was September 1, 2012; however, recent reports indicate that no specific timeline exists.[16] If the estimated return to service is not accelerated, SONGS would return to service after the peak-demand period in WECC-CAMX-US of July 2012. This could pose operational challenges in Southern California and lead to situations in which there is an increased probability of Firm load shedding to maintain the reliable operation of the bulk power system.

Figure 7: Preparations Yield Sufficient Planning Margins[17]

Huntington Beach units 3 & 4 increase import capability to San Diego.

Load	Mild Conditions	Heavy Load		Mild Conditions	Heavy Load
	4438	4882		4438	4882
Total gen	3048	3048		3048	3048
Import capability	**2100**	**2100**	➡	**2450**	**2450**
Load can be served	5148	5148		5498	5498
Reserves available	710	266		1060	616
Reserve requirement	603	603		603	603
Reserve margin	107	-337	➡	457	13

WECC resource adequacy and transmission modeling show sufficient transfer capability exists between Southern California and its neighboring areas, which in real-time should alleviate any capacity deficiencies within the San Diego and Los Angeles basins. The WECC Reliability Coordinator and CAISO continue to closely monitor developments in Southern California including the outage of the SONGS facility as well as other generation outages to ensure reliable operation of the bulk power system during the summer operating period.

In addition to the outages at SONGS, the Intermountain Generating Station (IGS) unit (900 MW), which also provides power to the Los Angeles Basin, has been forced out of service since December 2011. The IGS unit is undergoing repairs, and it is expected to return to service by the start of the summer operating period on June 1, 2012. At time of publishing, no other entities have reported long-term maintenance outages to WECC that may not finish on time or that could impact the reliability of the bulk power system.

[16] http://www.caiso.com/Documents/SCE_ISO-ClarifyPlanningDatesandProcessRegardingSanOnofre.pdf
[17] http://www.caiso.com/Documents/BriefingSummer2012OperationsPreparedness-Presentation-Mar2012.pdf

Enhanced operations and planning approaches instituted in response to September 2011 southwest outage

During an 11 minute period on the afternoon of September 8, 2011, a system disturbance occurred in the Pacific Southwest, that lead to cascading outages, which left approximately 2.7 million customers without power. The outages affected parts of Arizona, Southern California, and Baja California, Mexico. The entire San Diego area was blacked out, with nearly one-and-a-half million customers impacted for up to 12 hours. The system is designed and operated to withstand the single largest contingency and operate reliably, even with an outage of a 500 kV transmission line as demonstrated on previous occasions.

2.7 million
Approximate number of customers impacted by 2011 outage

After the outages occurred, the impacted entities promptly instituted their respective restoration processes. The affected customer load was restored approximately 12 hours after the initiating event.

The September 8, 2011 event stemmed primarily from weaknesses in two areas: operations planning and real-time situational awareness. These same weaknesses were identified in the August 2003 blackout that affected an estimated 50 million people in the Northeastern United States and Canada. Without adequate operations studies and situational awareness, entities responsible for operating and overseeing the transmission system could not ensure reliable operations within System Operating Limits (SOLs) or prevent cascading outages in the event of a single contingency, such as the loss of a single transmission line.

With regard to operations planning, some of the impacted entities' seasonal, next-day, and real-time studies do not adequately consider: (1) operations of facilities in external networks, including the status of transmission facilities, expected generation output, and load forecasts; (2) external contingencies that could impact their systems or internal contingencies that could impact their neighbors' systems; and (3) the impact on bulk power system reliability of internal and external sub-100 kV facilities. As a result, these entities' operations studies did not accurately and fully predict the impact of the loss of transmission elements. If the impacted entities had more accurately predicted the magnitude of these contingencies prior to the event, appropriate pre-contingency measures, such as dispatching additional generation to mitigate overloads and prevent cascading outages, could have been taken.

The September 8th event also exposed some entities' lack of adequate real-time situational awareness of conditions and contingencies throughout the WECC Region. For example, many entities' real-time tools, such as State Estimator and Real-Time Contingency Analysis (RTCA), are restricted by models that do not accurately or fully reflect the facilities and operations of external networks. Also, some entities' real-time tools are not adequate to alert operators to significant conditions or potential contingencies on their systems or neighboring systems. The lack of adequate situational awareness limits entities' ability to identify and plan for the next most critical contingency to prevent instability, uncontrolled separation, or cascading outages. If some of the impacted entities had been aware of real-time external conditions and performed (or reviewed) studies on the conditions prior to the onset of the event on September 8, 2011, then they could have been better prepared for the impacts when the event started and avoided the cascading that ensued.

To improve situational awareness in the WECC region recommendations were made to: (1) expand entities' external visibility in their models through, for example, improved data sharing and expanded use of Inter-Control Center Communications Protocol (ICCP) data links or similar technology; (2) improve the use of real-time tools to ensure the constant monitoring of potential contingencies; and (3) improve communications between entities to help maintain situational awareness.

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Number of specific recommendations in FERC/NERC Joint Inquiry Report

In addition to the operations planning and situational awareness issues, a host of other factors contributed to the September 8th event. For example, the WECC RC and impacted entities do not consistently recognize the adverse impact that sub-100 kV facilities can have on BPS reliability. Accordingly, the joint inquiry report recommended ensuring that facilities that can impact BPS reliability, regardless of voltage level, are classified as part of the bulk power system (BPS) and/or studied as part of entities' long-term and operations planning.

The joint inquiry report also found some significant issues with protection system planning and coordination. One recommendation was for Transmission Owners (TOs) to review their transformers' overload protection relay settings and philosophy within the context of prevailing industry practice, which applies settings in the range of 150 to 200 percent of the transformers' normal rating. TOs and transmission operators (TOP) should also plan to take proper pre-contingency mitigation measures before a facility loads to its tripping threshold and is automatically removed from service. The September event shows that all protection systems and separation schemes should be studied to understand their impact on BPS reliability and to ensure their operation or misoperation does not have unintended and undesirable effects.

In May 2012, NERC and the Federal Energy Regulatory Commission (FERC) jointly issued a report on the September 8, 2011 blackout.[18] The report identified 27 near, medium, and long-term recommendations that should be implemented in response to the lessons-learned from the investigation.

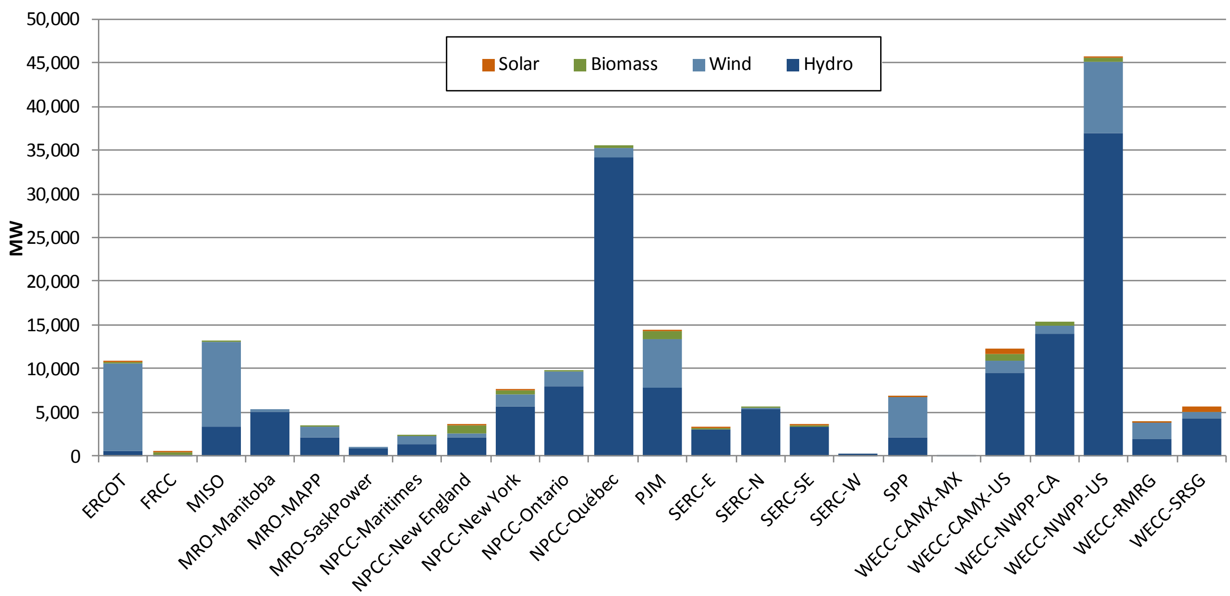
Several entities within WECC have taken, or are in the process of taking actions to prevent similar disturbances in the future. These actions include the implementation of additional real-time data exchange and coordination with additional entities in the Southwest. These processes will help facilitate a more detailed monitoring capability of neighboring systems in their energy management systems and real-time contingency analysis applications. In addition, the WECC RC has coordinated the development of an interim monitoring procedure of the San Diego and Imperial Valley areas with specific actions that will be taken for overload conditions.

[18] NERC – FERC Joint Inquiry Report into September 8, 2011 Arizona-California Outage http://www.nerc.com/fileUploads/File/News/AZOutage_Report_01MAY12.pdf.

Variable generation continues to increase in most assessment areas

During the summer of 2012, variable generation is forecast to increase in most assessment areas across North America. Specifically, this assessment notes significant increases in nameplate wind capacity in MISO, ERCOT, and NPCC-New England (ISO-NE). Other forms of variable generation, such as solar and other renewables capacities are not expected to significantly increase during the 2012 summer operating period. Figure 8 shows the nameplate renewable capacity (biomass, hydro, solar, and wind) for the 2012 summer for all assessment areas. NERC-wide, a total of 4,576 MW of nameplate wind generation has been installed since last year, reflecting a modest increase of 1,880 MW of expected capacity on-peak.

Figure 8: Nameplate Renewable Capacity for 2012 Summer



Variable resources – especially wind – are growing in nameplate capacity and becoming an important portion of the generation mix in many areas of North America. It is vital to ensure that these variable resources are reliably integrated into the bulk power system, and that both planning and operational challenges are addressed.[19]

New technologies have decreased the cost of producing electricity from wind, and tax incentives for renewable energy, as well as the introduction of state and provincial renewable portfolio standards, has lead to subsequent growth in NERC-wide wind resources. Generation from wind in the United States alone increased from about 6 billion kilowatt-hours (kWh) in 2000 to approximately 120 billion kWh in 2011.

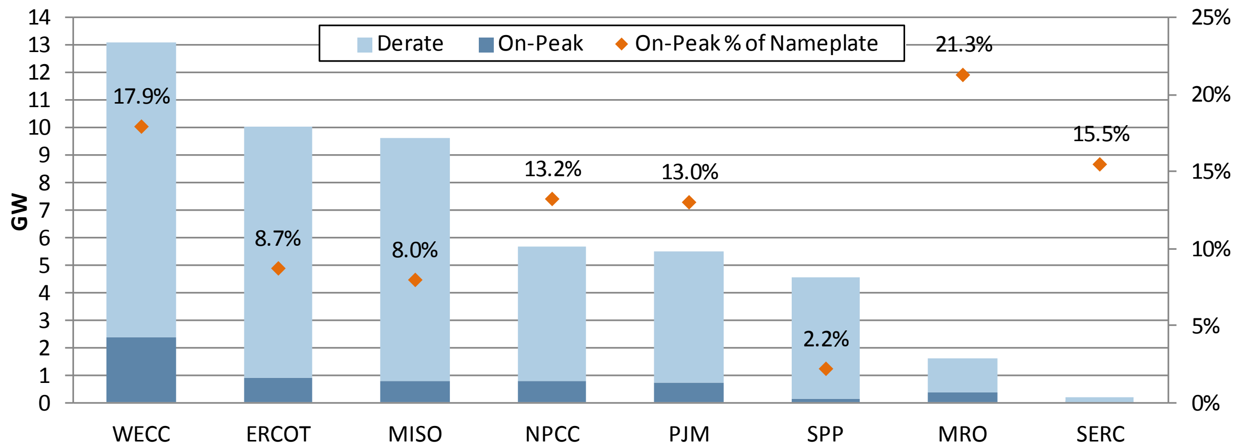
However, the actual capacity output of wind plants during times of peak demand generally amount to a fraction of nameplate capacity. Expected on-peak capacity typically accounts for between zero and 21.3 percent of an assessment area's entire nameplate wind capacity.[20] As noted by NERC in prior

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

[20] Within NPCC, the Quebec Assessment Area discounts wind 100 percent for summer on-peak capacity.

assessments, consistent methods to determine on-peak wind capacity are needed to ensure uniform measurement and resource adequacy assumptions.[21] As wind generation becomes a more significant contributor to an area's capacity mix, probabilistic planning techniques will be needed. More consistency is being achieved due to more experience with larger portfolios of wind generation. Figure 9 shows the nameplate and on-peak 2012 summer wind capacity expected output by assessment area.

Figure 9: Nameplate and On-Peak Summer Wind Output by Major Assessment Areas



Operationally, an increase in wind resources continues to challenge operators with the inherent swings, or ramps, in power output. In certain areas, where large concentrations of wind resources have been added, system planners must accommodate added variability by increasing the amount of available regulating reserves, and potentially carrying additional operating reserves. Because weather plays a key factor in determining wind output, enhancing Regional wind forecasting systems can provide more accurate output projections. Other methods include wind curtailment and limitation procedures used when generation exceeds the available regulating resources. In this respect, operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures and tools must be enhanced to assist operators in maintaining bulk power system reliability.

[21] Currently, Planning Coordinators use different methods to determine expected on-peak values of wind capacity. The Integration of Variable Generation Task Force is addressing this issue. The report *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* is available on the NERC website at: http://www.nerc.com/files/IVGTF1-2.pdf.

Demand-side management key in maintaining reliability this summer

100 %

increase of expected on-peak demand response since 2006

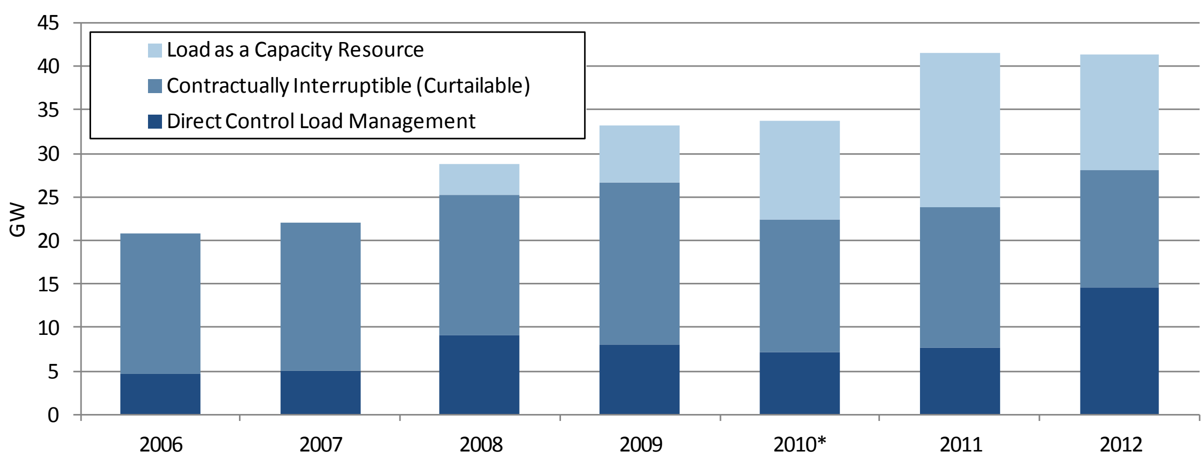
Demand-side management programs, which include conservation, energy efficiency, and a variety of demand response programs, provide the electric power industry the ability to reduce peak demand and to potentially defer the need for additional future generation or transmission. With tight margins in some areas, successful deployment of demand response will be critical for maintaining reliability this summer. Depending on summer conditions, demand response may be used more often this summer in areas with tight margins, such as Texas and Southern California.

Demand-side management is the term for activities or programs undertaken by a utility or an ISO/RTO with electricity end-users to influence the amount or timing of electricity they use. NERC collects controllable capacity demand response (CCDR) programs in four categories. These four types of demand response programs support reliability and are counted on to meet resource adequacy requirements.

- Direct Control Load Management (DCLM)
- Contractually Interruptible (Curtailable)
- Critical Peak Pricing (CPP) with Control[22]
- Load as a Capacity Resource

Demand response programs for this summer total approximately 40,200 MW for all of NERC.[23] Growth in demand response has slowed and actually decreased this summer compared to last summer's available capacity of approximately 41,500 MW, as shown in Figure 10. However, expected on-peak capacity for NERC overall has doubled since 2006.

Figure 10: NERC-Wide Demand Response Projected On Peak



*Reflects updated 2010 PJM data for Load as a Capacity Resource.

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[22] Not shown below since this type of program has less than 100 MW of NERC-wide availability.

[23] Demand Response is not a shareable resource, but is largely used for local-area reliability within a single operating entity. The total NERC value is only a general indicator or reference for growth in demand response resources.

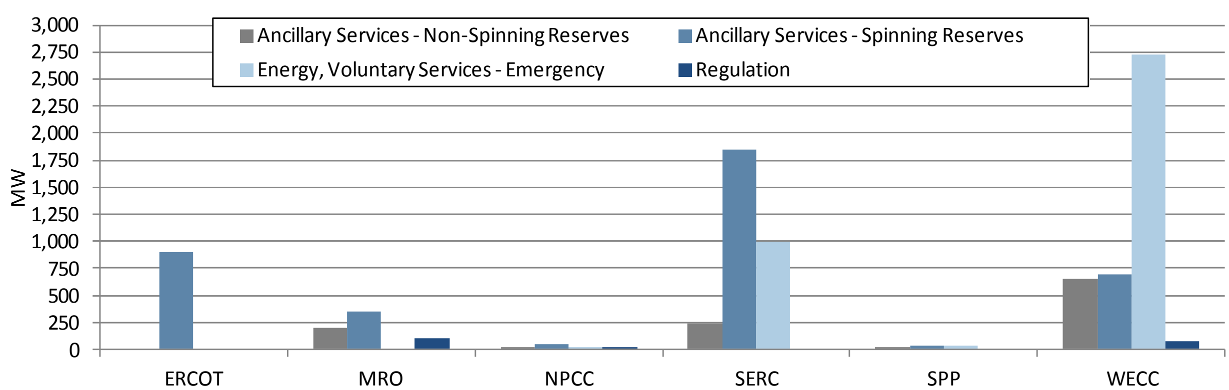
During the 2012 summer operating period, system operators may deploy demand response to either manage peak demand or to provide contingency reserves. Figure 11 shows available demand response capability across the North American bulk power system for the 2012 summer operating period. In almost all assessment areas, flat or slightly increased demand response participation is projected over the assessment timeframe. PJM and MISO administer the most demand response with 11,647 MW and 8,052 MW of demand response, respectively. These relatively large demand response participation values represent about 8 percent of the Total Internal Demand for each of the areas.

Figure 11: 2011 and 2012 Summer Demand Response by Assessment Area

	2011 Total DR	2012 Total DR	Change (MW)	Demand-Side	Supply-Side
ERCOT	1,433	1,471	38	1,471	
FRCC	3,141	3,183	42	3,183	
MISO	7,819	8,052	233	4,529	3,523
MRO-Manitoba	227	225	-2		225
MRO-MAPP	60	177	117	84	93
MRO-SaskPower	91	91	0	91	
NPCC-Maritimes	0	222	222		222
NPCC-New England (ISO-NE)	2,535	2,106	-429	978	1,128
NPCC-New York (NYISO)	2,053	2,165	112		2,165
NPCC-Ontario	0	1,326	1,326		1,326
NPCC-Québec	0	0	0		0
PJM	11,600	11,647	47	11,647	
SERC-E	1,694	1,878	184	1,878	
SERC-N	1,915	1,536	-379	1,536	
SERC-SE	1,704	1,774	70	1,774	
SERC-W	873	11	-862	11	
SPP	1,252	1,136	-115	1,136	
WECC-CAMX-MX	0	0	0		0
WECC-CAMX-US	2,204	2,211	7	2,211	
WECC-NWPP-CA	22	12	-10	12	
WECC-NWPP-US	1,256	1,225	-31	1,225	
WECC-RMRG	408	447	39	447	
WECC-SRSG	449	512	63	512	

Additional flexibility is provided to operators who facilitate the use of demand response resources to support local reliability issues and other system constraints as needed. For example, demand response is being used more and more to provide ancillary services, though these programs are still in their infancy and only a small amount of capacity provides these services, shown in Figure 12. Technological improvements in activation methods, as well as measurement and verification reinforce operator's confidence in demand resources in providing fast-acting response when grid conditions are stressed.

Figure 12: Demand Response Used to Provide Ancillary Services



The impact of potentially extreme weather events on bulk power system reliability

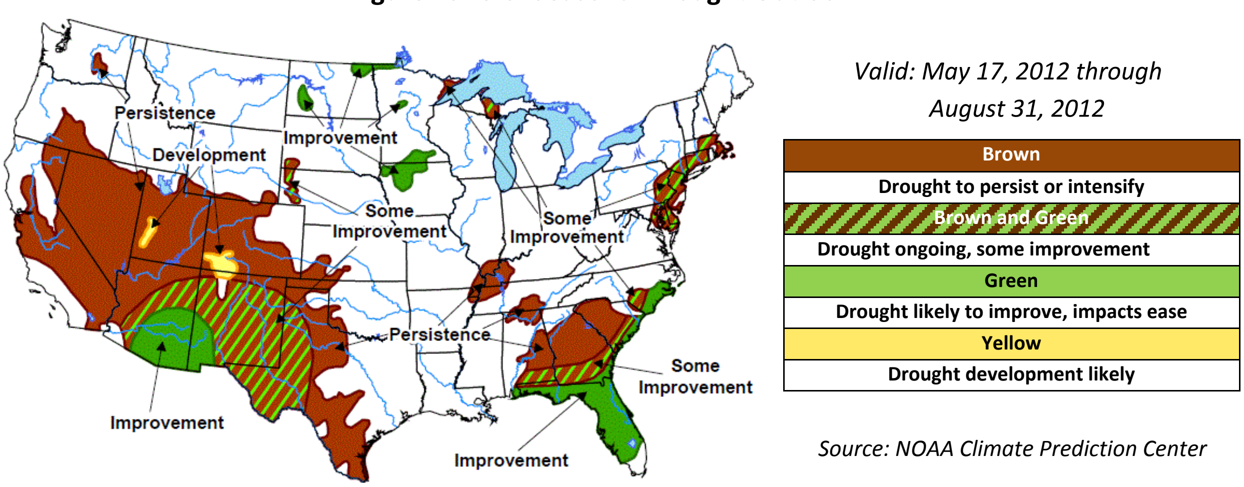
Extreme weather is based on an event's climatologically expected distribution.[24] For example, an event is called extreme in this sense if it lies in the tails of the climatological distribution, occurring less than 5 percent of the time.[25] Extreme events, by definition, are rare. Weather experienced during the 2010/2011 winter in Texas serves as an example of extreme weather, when temperatures dropped to a level that does not often occur.[26] The prolonged and extreme temperatures in Texas significantly stressed the power system, which resulted in the calling of two "Alert 2" level Energy Emergency Alerts (EEAs).[27]

For the purposes of this assessment, no attempt was made to forecast or predict the occurrence of extreme events such as extreme temperatures, precipitation, or development of extreme drought conditions. Instead, NERC identifies and highlight forecast observations that may have an impact on the reliable operation of the bulk power system. On-going trends, such as drought throughout the southwestern United States, are not expected to be a major factor during the 2012 summer, though still in the range of possibilities of impacting operations.

Drought

Overall, the current drought outlook from the National Oceanic and Atmospheric Administration (NOAA) is not optimistic for the 2012 summer operating period.[28] Substantial improvement is expected only in southern New England, the southern half of Florida with the onset of its rainy season, western North Dakota, and the Southwest. Drought should persist where it exists today and may expand to cover the central Rockies. Overall, there appears to be a generally low risk of large amounts of generator derates or outages this summer due to water availability. Figure 13 shows the latest drought outlook by NOAA.

Figure 13: U.S. Seasonal Drought Outlook



Source: NOAA Climate Prediction Center

[24] Climate is defined as the weather conditions prevailing in an area in general or over a long period.

[25] Extreme Weather Events and their Probabilistic Prediction by the NCEP Ensemble Forecast System, Yuejian Zhu[1] and Zoltan Toth http://www.emc.ncep.noaa.gov/gmb/ens/target/ens/albapr/albapr.html

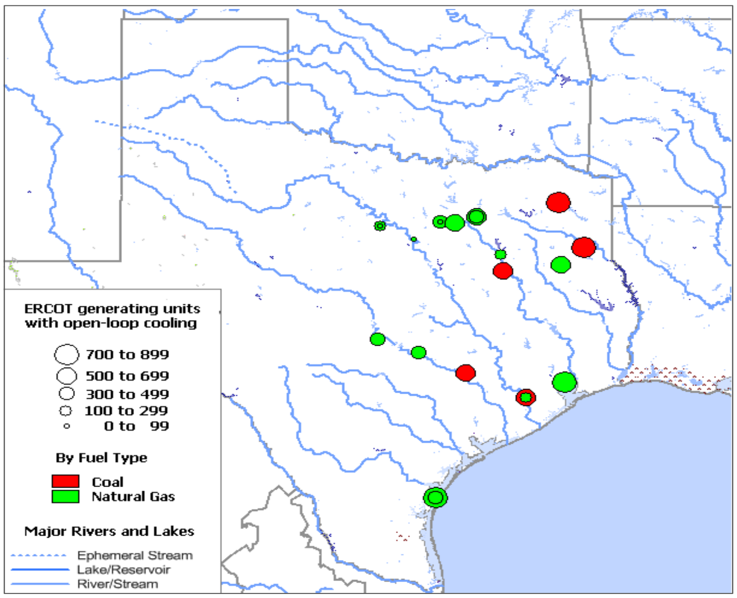
[26] http://www.nerc.com/files/SW_Cold_Weather_Event_Final_Report.pdf

[27] http://www.nerc.com/page.php?cid=4|331|341 and http://www.nerc.com/page.php?cid=4|331|335

[28] The NOAA drought outlook is based on short, medium, and long-range forecasts, initial conditions, past years with similarly-evolving weather, equatorial Pacific sea surface temperature patterns, objective weather and climate model output, and climatology.

During late summer in ERCOT, 85 percent of Texas was in “Exceptional Drought” status. However, recent precipitation in the eastern portion of Texas have improved rainfall deficits and the latest information from ERCOT indicate significant impacts caused by drought conditions are less likely. Further, a majority of the larger generation units that require cooling water are located in eastern Texas where drought conditions are not a concern, as shown in Figure 14. Conversely, the Brazos and Sabine River basins in the east and south are experiencing more persistent drought conditions. ERCOT will continue to monitor reservoir levels and the potential impact on the availability of once-through or open-loop cooling water-dependent generation.

Figure 14: ERCOT Generating Units with Open-Loop Cooling and Large Average Withdrawals



While water planning is not a function of ERCOT, significant steps have been taken to minimize the risk of generator outages and derates such as implementing water conservations programs, optimization of water reuse and recycling, minimizing water consumption, and using gray or lower quality water for cooling. In more extreme cases, intake structures could be modified to increase the relative water head levels from the pump intakes. Earlier this year, ERCOT held a *Drought Best Practices Workshop,*[29] which brought area stakeholders together to discuss mitigation measures that can be applied to minimize drought impacts.

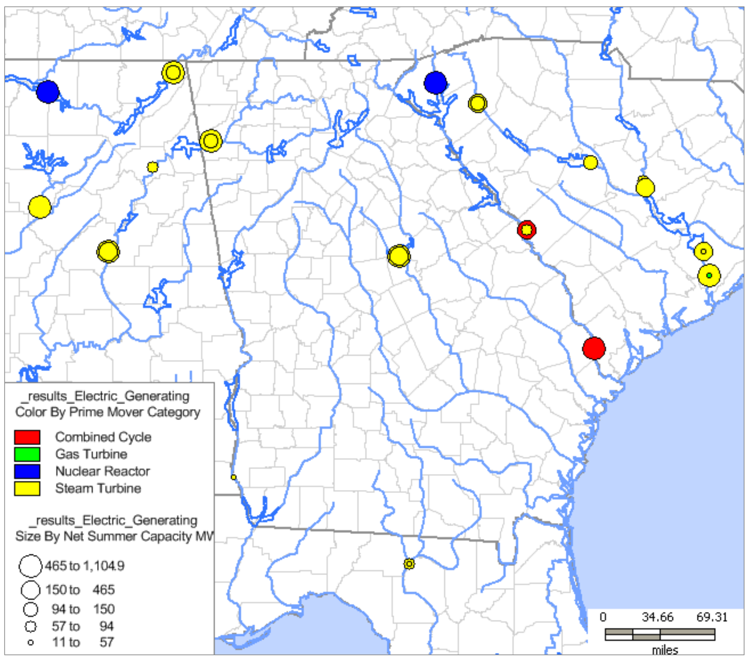
Some persistent drought conditions could also impact WECC. The western areas experienced a relatively warm and dry 2011/2012 winter, resulting in sparse snow pack in some areas. Runoff forecasts for the California basins are at or below 1/3 of normal conditions, while the Colorado River Basin is in its 12th year of a persistent drought. However, a March Columbia River flow forecast was at 93 percent of the 30-year average flow, measured at The Dalles, Oregon. It is expected that reduced river flows will result in increased thermal-based energy generation, but will not significantly impact the ability to serve peak demand.[30]

[29] http://www.ercot.com/calendar/2012/02/20120227-OTHER

[30] WECC models use a stress case, which includes adverse hydro conditions, to assess resource adequacy and power flows across the Western Interconnection.

Persistent drought conditions are also affecting the southeast states of Alabama, Georgia, and South Carolina (portions of the SERC-SE and SERC-E Assessment Areas). Within these three states, approximately 19,000 MW of generation within the drought affected areas require open-loop cooling, shown in Figure 15.[31] Additionally, just over 4,000 MW of on-peak hydro capacity is also in this area. Significant derates and/or complete unit outages due to a lack of cooling water could expose the southeastern areas to capacity shortages in extreme scenarios; however, reserve margins in these areas are more than sufficient to provide system operators with alternative resources should reservoir water levels fall significantly.

Figure 15: Southeast Generating Units with Open-Loop Cooling and Large Average Withdrawals



Temperature

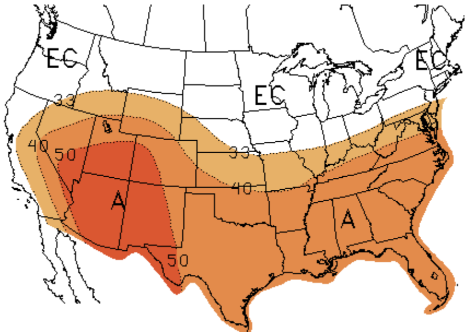
The temperature outlook for this summer indicates an increased probability of below normal mean temperatures in the Great Plains area of the United States, as indicated by NOAA models and tools.[32] Probabilities of above normal mean temperatures exist in the WECC-SRSG, ERCOT, all areas of SERC, PJM, and FRCC.

The entirety of Canada is currently forecast to be above normal mean temperatures for the months of June, July and August. However, there is significant reserve capacity available to meet increasing demand in all Canadian provinces. U.S. and Canada temperature forecasts are shown in Figure 16 and Figure 17.

[31] Excludes units located on the Atlantic Ocean coast.

[32] The climatic normal are based on conditions between 1981 and 2011, following the World Meteorological Organization convention of using the most recent three (3) decades as the climatic reference period. The probability anomalies for temperature and precipitation based on these new normal better represent short term climatic anomalies than the forecasts based on older baselines (temperature and precipitation).

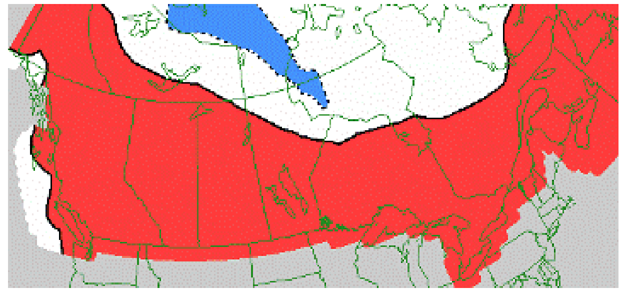
Figure 16: U.S. Summer Mean Temperature Probability Outlook, June to August 2012[33]



Source: NOAA Climate Prediction Center

A (Orange)	Above-Normal Temperatures Forecast
EC (White)	Equal Chance of Above- or Below-Normal Temperatures
B (Blue)	Below-Normal Temperatures Forecast

Figure 17: Canada Summer Mean Temperature Probability Outlook, June to August 2012[34]



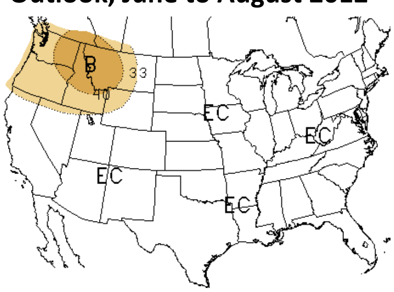
Source: Environment Canada

Red	Above-Normal Temperatures Forecast
White	Equal Chance of Above- or Below-Normal Temperatures
Blue	Below-Normal Temperatures Forecast

Precipitation

Summer precipitation outlooks are based on decadal climate variability and trends. Probabilities of below median precipitation are increased for portions of the Pacific Northwest. The remainder of the U.S. is expected to have average precipitation throughout the summer months. In Canada, below average precipitation levels are predicted across a number of Canadian provinces. A lack of significant precipitation during the 2012 summer months should not have an impact on resource adequacy for the summer operating period, but could have a resource adequacy impact of hydro generation-dependent areas for the 2012/2013 winter operating period. Precipitation forecasts for the U.S. and Canada are shown in Figure 18 and Figure 19.

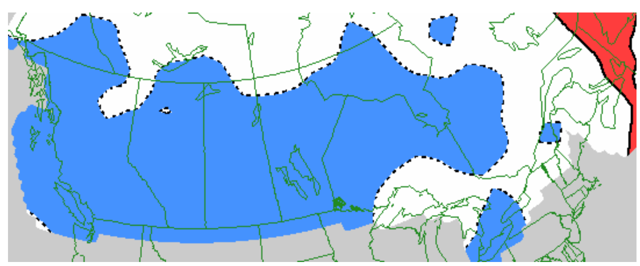
Figure 18: U.S. Summer Mean Precipitation Outlook, June to August 2012



Source: NOAA Climate Prediction Center

A (Green)	Above-normal Precipitation Forecast
EC (White)	Equal Chance of Above- or Below-Normal Precipitation
B (Brown)	Below-Normal Precipitation Forecast

Figure 19: Canada Mean Summer Precipitation Outlook, June to August 2012



Source: Environment Canada

Red	Above-normal Precipitation Forecast
White	Equal Chance of Above- or Below-Normal Precipitation
Blue	Below-normal Precipitation Forecast

[33] http://www.cpc.ncep.noaa.gov/index.php
[34] http://www.weatheroffice.gc.ca/saisons/index_e.html

Lower global LNG gas supply may impact LNG-dependent generation in New England; ISO to implement proactive measures

Under normal weather and system conditions, New England's electric power supplies are expected to be adequate to meet regional demand this summer. However, reduced and uncertain supplies of liquefied natural gas (LNG) to power generation in the Northeast Massachusetts/Greater Boston area during the summer could create local reliability challenges to this portion of the power grid. Extreme weather conditions combined with significant unexpected generator outages could further stress the situation.

With below-normal LNG supplies to New England, system operators from ISO-NE are working with local stakeholders along with federal, state, and local authorities to mitigate impacts for the 2012 summer. While these solutions will help minimize impacts this summer, a long-term solutions are currently being developed to address duel diversity and resource availability issues.

Projected Demand, Resources, and Reserve Margins

NERC Assessment Area Reserve Margins for the 2012 Summer Peak Month[35]

Country / Assessment Area	Demand		Capacity Resources			Planning Reserve Margins			
	Total Internal	Net Internal	Existing-Certain & Net Firm	Anticipated	Prospective	Existing-Certain & Net Firm	Anticipated	Prospective	Reference Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	66,076	64,605	73,211	73,334	73,334	13.32%	13.51%	13.51%	13.75%
FRCC	45,613	42,430	54,986	54,241	54,297	29.59%	27.84%	27.97%	15.00%
MISO	93,102	88,573	112,285	113,952	127,299	26.77%	28.65%	43.72%	16.70%
MRO-MAPP	4,799	4,715	5,788	6,082	6,082	22.77%	29.01%	29.01%	15.00%
NPCC-New England (ISO-NE)	27,440	26,462	33,448	33,585	34,815	26.40%	26.92%	31.57%	15.00%
NPCC-New York (NYISO)	33,295	33,295	39,024	39,024	39,024	17.21%	17.21%	17.21%	16.00%
PJM	153,782	142,135	185,641	185,641	190,471	30.61%	30.61%	34.01%	15.60%
SERC-E	43,255	41,378	50,696	50,696	50,696	22.52%	22.52%	22.52%	15.00%
SERC-N	45,102	43,566	57,079	57,957	59,445	31.02%	33.03%	36.45%	15.00%
SERC-SE	48,895	47,121	62,833	62,883	64,799	33.34%	33.45%	37.52%	15.00%
SERC-W	25,403	25,392	34,591	36,569	37,443	36.23%	44.02%	47.46%	15.00%
SPP	54,051	52,915	63,549	64,908	71,831	20.10%	22.66%	35.75%	13.60%
WECC-CAMX	49,490	47,279	54,402	54,478	54,478	15.07%	15.23%	15.23%	15.13%
WECC-NWPP	41,523	40,298	47,038	47,708	47,708	16.73%	18.39%	18.39%	15.67%
WECC-RMRG	10,503	10,056	13,495	13,875	13,875	34.20%	37.97%	37.97%	14.70%
WECC-SRSG	29,402	28,890	35,208	35,388	35,388	21.87%	22.49%	22.49%	13.50%
TOTAL-UNITED STATES	**771,732**	**739,110**	**923,274**	**930,321**	**960,985**	**24.92%**	**25.87%**	**30.02%**	**15.00%**
MRO-Manitoba Hydro	3,143	3,143	4,296	4,516	4,641	36.68%	43.68%	47.66%	12.00%
MRO-SaskPower	3,044	2,953	3,647	3,647	3,888	23.50%	23.50%	31.68%	13.00%
NPCC-Maritimes	3,392	3,392	4,821	4,821	4,821	42.13%	42.13%	42.13%	15.00%
NPCC-Ontario (IESO)	23,409	23,409	29,281	30,451	36,735	25.08%	30.08%	56.92%	20.40%
NPCC-Québec	20,988	20,988	32,582	32,356	32,356	55.24%	54.16%	54.16%	10.00%
WECC-NWPP	17,769	17,757	26,597	26,627	26,627	49.78%	49.95%	49.95%	12.36%
TOTAL-CANADA	**71,745**	**71,642**	**101,223**	**102,417**	**109,067**	**41.29%**	**42.96%**	**52.24%**	**10.00%**
TOTAL-MÉXICO	**2,264**	**2,264**	**2,763**	**2,763**	**2,763**	**22.04%**	**22.04%**	**22.04%**	**11.86%**
TOTAL-NERC	**843,962**	**811,237**	**1,021,614**	**1,029,890**	**1,067,204**	**25.93%**	**26.95%**	**31.55%**	**15.00%**
EASTERN INTERCONNECTION	**607,725**	**580,878**	**741,965**	**748,972**	**786,286**	**27.73%**	**28.94%**	**35.36%**	**15.00%**
ERCOT INTERCONNECTION	**66,076**	**64,605**	**73,211**	**73,334**	**73,334**	**13.32%**	**13.51%**	**13.51%**	**13.75%**
QUÉBEC INTERCONNECTION	**20,988**	**20,988**	**32,582**	**32,356**	**32,356**	**55.24%**	**54.16%**	**54.16%**	**10.00%**
WESTERN INTERCONNECTION	**149,173**	**144,766**	**173,855**	**175,228**	**175,228**	**20.09%**	**21.04%**	**21.04%**	**15.00%**

[35] This table reflects the non-coincidental NERC-wide peak, with Total Internal Demand projection for the peak month of each assessment area during the 2012 summer. The following four tables include the monthly projections for June, July, August and September. For additional information, please refer to Appendix V.

NERC Assessment Area Reserve Margins for June 2012

Country / Assessment Area	Demand		Capacity Resources			Planning Reserve Margins			
	Total Internal	Net Internal	Existing-Certain & Net Firm	Anticipated	Prospective	Existing-Certain & Net Firm	Anticipated	Prospective	Reference Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	59,841	58,370	73,211	73,334	73,334	25.43%	25.64%	25.64%	13.75%
FRCC	42,589	39,459	54,986	54,986	55,042	39.35%	39.35%	39.49%	15.00%
MISO	86,548	82,019	111,407	113,072	127,291	35.83%	37.86%	55.20%	16.70%
MRO-MAPP	4,466	4,382	5,818	6,112	6,112	32.78%	39.49%	39.49%	15.00%
NPCC-New England (ISO-NE)	25,854	24,876	33,471	33,608	34,815	34.55%	35.10%	39.95%	15.00%
NPCC-New York (NYISO)	33,295	33,295	38,953	38,953	38,953	16.99%	16.99%	16.99%	16.00%
PJM	143,028	131,381	185,641	185,641	190,471	41.30%	41.30%	44.98%	15.60%
SERC-E	41,324	39,451	50,696	50,696	50,696	28.50%	28.50%	28.50%	15.00%
SERC-N	42,005	40,940	57,079	57,957	59,459	39.42%	41.57%	45.24%	15.00%
SERC-SE	46,732	44,969	62,833	62,883	64,749	39.72%	39.84%	43.99%	15.00%
SERC-W	23,041	23,030	34,591	36,569	37,500	50.20%	58.79%	62.83%	15.00%
SPP	49,697	48,730	63,549	64,654	71,577	30.41%	32.68%	46.88%	13.60%
WECC-CAMX	45,313	43,102	53,374	53,437	53,437	23.83%	23.98%	23.98%	15.13%
WECC-NWPP	38,540	37,315	46,035	46,710	46,710	23.37%	25.18%	25.18%	15.67%
WECC-RMRG	10,503	10,056	13,495	13,875	13,875	34.20%	37.97%	37.97%	14.70%
WECC-SRSG	26,933	26,421	41,595	41,753	41,753	57.43%	58.03%	58.03%	13.50%
TOTAL-UNITED STATES	**719,709**	**687,796**	**926,733**	**934,240**	**965,774**	**34.74%**	**35.83%**	**40.42%**	**15.00%**
MRO-Manitoba Hydro	3,079	3,079	3,911	3,997	4,122	27.02%	29.81%	33.87%	12.00%
MRO-SaskPower	3,044	2,953	3,669	3,669	3,907	24.27%	24.27%	32.31%	13.00%
NPCC-Maritimes	3,315	3,315	3,826	3,826	3,826	15.41%	15.41%	15.41%	15.00%
NPCC-Ontario (IESO)	22,769	22,769	29,551	29,971	35,985	29.79%	31.63%	58.04%	20.40%
NPCC-Québec	20,439	20,439	31,784	31,508	31,508	55.51%	54.16%	54.16%	10.00%
WECC-NWPP	17,769	17,757	26,597	26,627	26,627	49.78%	49.95%	49.95%	12.36%
TOTAL-CANADA	**70,415**	**70,312**	**99,338**	**99,598**	**105,974**	**41.28%**	**41.65%**	**50.72%**	**10.00%**
TOTAL-MÉXICO	**1,992**	**1,992**	**2,522**	**2,522**	**2,522**	**26.61%**	**26.61%**	**26.61%**	**11.86%**
TOTAL-NERC	**792,115**	**760,100**	**1,024,679**	**1,032,435**	**1,070,345**	**34.81%**	**35.83%**	**40.82%**	**15.00%**
EASTERN INTERCONNECTION	**570,785**	**544,648**	**739,982**	**746,595**	**784,504**	**35.86%**	**37.08%**	**44.04%**	**15.00%**
ERCOT INTERCONNECTION	**59,841**	**58,370**	**73,211**	**73,334**	**73,334**	**25.43%**	**25.64%**	**25.64%**	**13.75%**
QUÉBEC INTERCONNECTION	**20,439**	**20,439**	**31,784**	**31,508**	**31,508**	**55.51%**	**54.16%**	**54.16%**	**10.00%**
WESTERN INTERCONNECTION	**141,050**	**136,643**	**179,703**	**180,999**	**180,999**	**31.51%**	**32.46%**	**32.46%**	**15.00%**

NERC Assessment Area Reserve Margins for July 2012

Country / Assessment Area	Demand		Capacity Resources			Planning Reserve Margins			
	Total Internal	Net Internal	Existing-Certain & Net Firm	Anticipated	Prospective	Existing-Certain & Net Firm	Anticipated	Prospective	Reference Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	60,696	59,225	73,211	73,334	73,334	23.62%	23.82%	23.82%	13.75%
FRCC	43,780	40,632	54,986	54,986	55,042	35.33%	35.33%	35.46%	15.00%
MISO	93,102	88,573	112,285	113,952	127,299	26.77%	28.65%	43.72%	16.70%
MRO-MAPP	4,799	4,715	5,788	6,082	6,082	22.77%	29.01%	29.01%	15.00%
NPCC-New England (ISO-NE)	27,440	26,462	33,448	33,585	34,815	26.40%	26.92%	31.57%	15.00%
NPCC-New York (NYISO)	33,295	33,295	39,024	39,024	39,024	17.21%	17.21%	17.21%	16.00%
PJM	153,782	142,135	185,641	185,641	190,471	30.61%	30.61%	34.01%	15.60%
SERC-E	43,255	41,378	50,696	50,696	50,696	22.52%	22.52%	22.52%	15.00%
SERC-N	44,221	42,822	57,079	57,957	59,445	33.29%	35.34%	38.82%	15.00%
SERC-SE	48,676	46,901	62,833	62,883	64,749	33.97%	34.08%	38.05%	15.00%
SERC-W	24,037	24,026	34,591	36,569	37,386	43.97%	52.21%	55.61%	15.00%
SPP	53,877	52,745	63,552	65,008	71,932	20.49%	23.25%	36.38%	13.60%
WECC-CAMX	49,490	47,279	54,402	54,478	54,478	15.07%	15.23%	15.23%	15.13%
WECC-NWPP	41,523	40,298	47,038	47,708	47,708	16.73%	18.39%	18.39%	15.67%
WECC-RMRG	9,949	9,502	11,853	12,233	12,233	24.74%	28.74%	28.74%	14.70%
WECC-SRSG	28,310	27,798	38,610	38,782	38,782	38.89%	39.51%	39.51%	13.50%
TOTAL-UNITED STATES	**760,232**	**727,786**	**925,038**	**932,918**	**963,476**	**27.10%**	**28.19%**	**32.38%**	**15.00%**
MRO-Manitoba Hydro	3,098	3,098	4,304	4,464	4,589	38.93%	44.09%	48.13%	12.00%
MRO-SaskPower	3,044	2,953	3,647	3,647	3,888	23.50%	23.50%	31.68%	13.00%
NPCC-Maritimes	3,211	3,211	4,545	4,545	4,545	41.54%	41.54%	41.54%	15.00%
NPCC-Ontario (IESO)	23,409	23,409	29,281	30,451	36,735	25.08%	30.08%	56.92%	20.40%
NPCC-Québec	20,551	20,551	31,437	31,211	31,211	52.97%	51.87%	51.87%	10.00%
WECC-NWPP	17,755	17,743	24,457	24,532	24,532	37.84%	38.26%	38.26%	12.36%
TOTAL-CANADA	**71,068**	**70,965**	**97,671**	**98,849**	**105,499**	**37.63%**	**39.29%**	**48.66%**	**10.00%**
TOTAL-MÉXICO	**2,146**	**2,146**	**2,570**	**2,570**	**2,570**	**19.75%**	**19.75%**	**19.75%**	**11.86%**
TOTAL-NERC	**833,446**	**800,897**	**1,020,204**	**1,029,263**	**1,066,470**	**27.38%**	**28.51%**	**33.16%**	**15.00%**
EASTERN INTERCONNECTION	**603,026**	**576,355**	**741,701**	**749,490**	**786,697**	**28.69%**	**30.04%**	**36.50%**	**15.00%**
ERCOT INTERCONNECTION	**60,696**	**59,225**	**73,211**	**73,334**	**73,334**	**23.62%**	**23.82%**	**23.82%**	**13.75%**
QUÉBEC INTERCONNECTION	**20,551**	**20,551**	**31,437**	**31,211**	**31,211**	**52.97%**	**51.87%**	**51.87%**	**10.00%**
WESTERN INTERCONNECTION	**149,173**	**144,766**	**173,855**	**175,228**	**175,228**	**20.09%**	**21.04%**	**21.04%**	**15.00%**

NERC Assessment Area Reserve Margins for August 2012

Country / Assessment Area	Demand		Capacity Resources			Planning Reserve Margins			
	Total Internal	Net Internal	Existing-Certain & Net Firm	Anticipated	Prospective	Existing-Certain & Net Firm	Anticipated	Prospective	Reference Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	66,076	64,605	73,211	73,334	73,334	13.32%	13.51%	13.51%	13.75%
FRCC	45,613	42,430	54,986	54,241	54,297	29.59%	27.84%	27.97%	15.00%
MISO	91,839	87,310	113,165	114,834	127,301	29.61%	31.52%	45.80%	16.70%
MRO-MAPP	4,725	4,641	5,830	6,124	6,124	25.60%	31.94%	31.94%	15.00%
NPCC-New England (ISO-NE)	27,440	26,462	33,484	33,621	34,815	26.54%	27.05%	31.57%	15.00%
NPCC-New York (NYISO)	33,295	33,295	39,024	39,024	39,024	17.21%	17.21%	17.21%	16.00%
PJM	147,557	135,910	185,641	185,641	190,471	36.59%	36.59%	40.14%	15.60%
SERC-E	42,816	40,931	50,696	51,521	51,521	23.86%	25.87%	25.87%	15.00%
SERC-N	45,102	43,566	57,079	57,957	59,445	31.02%	33.03%	36.45%	15.00%
SERC-SE	48,895	47,121	62,833	62,883	64,799	33.34%	33.45%	37.52%	15.00%
SERC-W	25,403	25,392	34,591	36,569	37,443	36.23%	44.02%	47.46%	15.00%
SPP	54,051	52,915	63,549	64,908	71,831	20.10%	22.66%	35.75%	13.60%
WECC-CAMX	44,690	42,479	49,027	49,104	49,104	15.42%	15.60%	15.60%	15.13%
WECC-NWPP	40,630	39,405	45,804	46,407	46,407	16.24%	17.77%	17.77%	15.67%
WECC-RMRG	10,346	9,899	12,003	12,383	12,383	21.25%	25.09%	25.09%	14.70%
WECC-SRSG	29,402	28,890	35,208	35,388	35,388	21.87%	22.49%	22.49%	13.50%
TOTAL-UNITED STATES	**757,880**	**725,251**	**916,131**	**923,938**	**953,687**	**26.32%**	**27.40%**	**31.50%**	**15.00%**
MRO-Manitoba Hydro	3,143	3,143	4,296	4,516	4,641	36.68%	43.68%	47.66%	12.00%
MRO-SaskPower	3,044	2,953	3,665	3,665	3,904	24.13%	24.13%	32.22%	13.00%
NPCC-Maritimes	3,182	3,182	4,860	4,860	4,860	52.73%	52.73%	52.73%	15.00%
NPCC-Ontario (IESO)	22,533	22,533	30,101	31,271	36,735	33.59%	38.78%	63.03%	20.40%
NPCC-Québec	20,988	20,988	32,582	32,356	32,356	55.24%	54.16%	54.16%	10.00%
WECC-NWPP	17,631	17,619	23,657	23,737	23,737	34.27%	34.73%	34.73%	12.36%
TOTAL-CANADA	**70,521**	**70,418**	**99,161**	**100,405**	**106,233**	**40.82%**	**42.59%**	**50.86%**	**10.00%**
TOTAL-MÉXICO	**2,264**	**2,264**	**2,763**	**2,763**	**2,763**	**22.04%**	**22.04%**	**22.04%**	**11.86%**
TOTAL-NERC	**830,665**	**797,933**	**1,015,465**	**1,024,517**	**1,060,093**	**27.26%**	**28.40%**	**32.85%**	**15.00%**
EASTERN INTERCONNECTION	**598,638**	**571,784**	**743,800**	**751,634**	**787,210**	**30.08%**	**31.45%**	**37.68%**	**15.00%**
ERCOT INTERCONNECTION	**66,076**	**64,605**	**73,211**	**73,334**	**73,334**	**13.32%**	**13.51%**	**13.51%**	**13.75%**
QUÉBEC INTERCONNECTION	**20,988**	**20,988**	**32,582**	**32,356**	**32,356**	**55.24%**	**54.16%**	**54.16%**	**10.00%**
WESTERN INTERCONNECTION	**144,963**	**140,556**	**165,873**	**167,192**	**167,192**	**18.01%**	**18.95%**	**18.95%**	**15.00%**

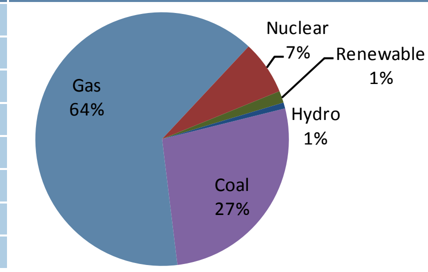
NERC Assessment Area Reserve Margins for September 2012

Country / Assessment Area	Demand		Capacity Resources			Planning Reserve Margins			
	Total Internal	Net Internal	Existing-Certain & Net Firm	Anticipated	Prospective	Existing-Certain & Net Firm	Anticipated	Prospective	Reference Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	56,506	55,035	73,211	73,334	73,334	33.03%	33.25%	33.25%	13.75%
FRCC	42,303	39,194	54,986	53,552	53,608	40.29%	36.63%	36.78%	15.00%
MISO	80,453	75,924	113,165	114,865	127,332	49.05%	51.29%	67.71%	16.70%
MRO-MAPP	4,339	4,255	5,864	6,158	6,158	37.80%	44.71%	44.71%	15.00%
NPCC-New England (ISO-NE)	23,417	22,439	30,907	31,044	34,815	37.74%	38.35%	55.15%	15.00%
NPCC-New York (NYISO)	24,715	24,715	35,293	35,293	35,293	42.80%	42.80%	42.80%	16.00%
PJM	129,163	117,516	185,641	185,641	190,471	57.97%	57.97%	62.08%	15.60%
SERC-E	39,083	37,227	50,314	51,139	53,157	35.15%	37.37%	42.79%	15.00%
SERC-N	40,859	39,933	57,079	57,957	59,857	42.93%	45.13%	49.89%	15.00%
SERC-SE	44,508	42,745	62,838	62,888	64,804	47.01%	47.12%	51.61%	15.00%
SERC-W	22,083	22,072	34,591	36,569	37,443	56.72%	65.68%	69.64%	15.00%
SPP	47,189	46,264	63,508	64,552	71,531	37.28%	39.53%	54.62%	13.60%
WECC-CAMX	46,027	43,816	50,509	50,575	50,575	15.27%	15.43%	15.43%	15.13%
WECC-NWPP	35,761	34,536	40,158	40,741	40,741	16.28%	17.97%	17.97%	15.67%
WECC-RMRG	9,205	8,758	11,370	11,750	11,750	29.83%	34.17%	34.17%	14.70%
WECC-SRSG	26,341	25,829	33,638	33,808	33,808	30.23%	30.89%	30.89%	13.50%
TOTAL-UNITED STATES	**671,952**	**640,258**	**903,071**	**909,866**	**944,678**	**41.05%**	**42.11%**	**47.55%**	**15.00%**
MRO-Manitoba Hydro	2,918	2,918	3,960	4,180	4,305	35.71%	43.25%	47.53%	12.00%
MRO-SaskPower	3,044	2,953	3,457	3,457	3,938	17.09%	17.09%	33.37%	13.00%
NPCC-Maritimes	3,392	3,392	4,821	4,821	4,821	42.13%	42.13%	42.13%	15.00%
NPCC-Ontario (IESO)	20,954	20,954	27,428	28,605	36,735	30.90%	36.51%	75.31%	20.40%
NPCC-Québec	20,829	20,829	32,808	32,582	32,582	57.51%	56.43%	56.43%	10.00%
WECC-NWPP	16,732	16,720	23,580	23,662	23,662	41.03%	41.52%	41.52%	12.36%
TOTAL-CANADA	**67,869**	**67,766**	**96,054**	**97,307**	**106,042**	**41.74%**	**43.59%**	**56.48%**	**10.00%**
TOTAL-MÉXICO	**2,214**	**2,214**	**2,704**	**2,704**	**2,704**	**22.15%**	**22.15%**	**22.15%**	**11.86%**
TOTAL-NERC	**742,035**	**710,238**	**999,480**	**1,007,520**	**1,051,067**	**40.72%**	**41.86%**	**47.99%**	**15.00%**
EASTERN INTERCONNECTION	**528,420**	**502,501**	**733,852**	**740,721**	**784,268**	**46.04%**	**47.41%**	**56.07%**	**15.00%**
ERCOT INTERCONNECTION	**56,506**	**55,035**	**73,211**	**73,334**	**73,334**	**33.03%**	**33.25%**	**33.25%**	**13.75%**
QUÉBEC INTERCONNECTION	**20,829**	**20,829**	**32,808**	**32,582**	**32,582**	**57.51%**	**56.43%**	**56.43%**	**10.00%**
WESTERN INTERCONNECTION	**136,280**	**131,873**	**159,609**	**160,884**	**160,884**	**21.03%**	**22.00%**	**22.00%**	**15.00%**

ERCOT

2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	72,947	-
Future-Planned	123	-
Supply-Side Demand Response	0	-
Net Capacity Transactions	264	-
Anticipated	**73,334**	**13.51%**
Existing-Other and Future-Other	0	-
Prospective	**73,334**	**13.51%**
Reference Margin Level	-	**13.75%**

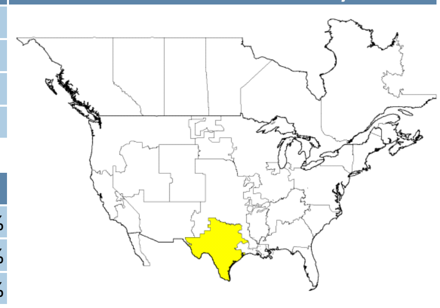
On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**63,531**	**64,605**
Demand-Side Demand Response (2012)	-	1,471
Supply-Side Demand Response (2011)	1,433	-
Total Internal	**64,964**	**66,076**

2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	63,531	1.69%
Actual Peak Demand	68,416	-5.57%
All-Time Summer Peak Demand (August 3, 2011)	68,416	-5.57%

Assessment Area Boundary



Note: Additional information regarding the methods and assumptions used in the development of the ERCOT seasonal assessment can be found in Appendix I and on the NERC website.[36]

Assessment Area Highlights

The ERCOT Region is an electric interconnection located entirely in the state of Texas that operates as a single Balancing Authority and Reliability Coordinator. The Anticipated Reserve Margin is expected to fall below the Reference Margin in August of the 2012 summer. Insufficient reserves during peak hours could result in emergency operating conditions, including the possibility of curtailing interruptible loads and even rotating outages of Firm loads. In order to minimize this risk, ERCOT is working with the Public Utility Commission of Texas (PUCT) and market participants to ensure that all potential resources, including the possible recall of mothballed units and increased demand response programs, are made available during the 2012 summer.

A total of 1,597 MW of on-peak capacity additions and units returning to service prior to the 2012 summer season, which includes 688 MW of mothballed units recalled by the collective efforts of the PUCT, market participants, and ERCOT. Capacity additions and units returning to service consist of 1260 MW of gas generation, 275 MW of coal, 35 MW of wind (with a nameplate capacity of 402 MW), and 27 MW of solar. According to the ERCOT demand forecast, Total Internal Demand is expected to decrease from the actual 2011 system peak of 68,416 MW to the forecasted 2012 peak of 66,195 MW.[37] This equates to a growth rate of -3.2 percent. The growth rate from last summer's forecasted peak load (64,964 MW), compared to this summer's forecasted peak load (66,195 MW) is based on the (50/50) average weather conditions is 1.9 percent.

[36] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

[37] Developed using average weather conditions and referred to as the "50/50" forecast.

According to currently available information, water availability is not expected to have a significant impact on generation output this summer season, even in the event that drought conditions as severe as last summer persist. No significant transmission constraints are expected to impact reliability during the upcoming summer season. Continued load growth throughout the planning horizon will require continued assessment and planning of new transmission assets in order to ensure reliable delivery of electricity to consumers.

Planning Reserve Margins

The Existing-Certain and Net Firm Transactions Reserve Margin is projected to be 13.3 percent, which is below the 13.75 percent Reference Margin for ERCOT. The Anticipated and Prospective Reserve Margins for the 2012 summer assessment period are both projected to be 13.5 percent, also below the ERCOT's Reference Margin. The ERCOT Reference Margin (referred to as the Planning Reserve Margin in ERCOT documentation) of 13.75 percent is established through a Loss-of-Load Events (LOLEv) analysis of no more than 0.1 events per year based on an updated probabilistic study completed in 2010.[38] **Error! Not a valid bookmark self-reference.** includes the 2011 and 2012 Reserve Margins for the ERCOT Assessment Area.

Table 1: ERCOT Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	**13.75%**	**13.75%**
Existing-Certain & Net Firm Transactions	**13.86%**	**13.32%**
Anticipated	**14.26%**	**13.51%**
Prospective	**14.26%**	**13.51%**

The Anticipated Reserve Margin for 2012, 13.5 percent, is lower than the 16.9 percent and 14.3 percent Anticipated Reserve Margin that was projected in NERC's *2011 Long-Term Reliability Assessment* and *2011 Summer Reliability Assessment,* respectively. The extreme hot and dry conditions experienced in ERCOT during the summer of 2011 (the hottest summer on record for any state) upwardly adjusted the calculated expectation of average weather conditions (derived from the past sixteen years of weather data). This adjustment, in expectation for average weather, has elevated the expected load forecast for 2012 (an increase of approximately 1.2 percent). Although the 2012 (and beyond) forecast has been adjusted upwards, the 2012 forecast peak demand is actually less than the 2011 actual peak demand.

The use of an extreme temperature assumption (90/10 scenario) produces a 2012 demand forecast of 67,492 MW,[39] or 2 percent higher than the average (50/50) weather profile. Using the 90/10 forecast for the 2012 summer season would produce a decrease in the reserve margins to the following levels: Existing-Certain and Net Firm Transactions: 8.5 percent; Anticipated: 8.7 percent; Prospective: 8.7 percent.

A 925 MW thermal plant that was originally scheduled to be available for the 2012 summer has been delayed and is not expected to be available until March 2013. Overall, the development of other

[38] http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_-_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip

[39] The 90/10 scenario was applied in the *Seasonal Assessment of Resource Adequacy for the ERCOT Region – Summer 2012*. (http://www.ercot.com/content/news/presentations/2012/SARA-Summer2012_V5.pdf).

capacity has lagged behind load growth in the ERCOT Region. ERCOT is currently working with the PUCT and market participants to ensure that all potential resources are made available during the 2012 summer season. ERCOT is actively pursuing market rule changes that will expand the number of resources that can participate in the Emergency Interruptible Load Service (EILS) program.[40,41] ERCOT is working with Transmission Service Providers (TSP) to better coordinate activation of load resources included in the TSP demand-response programs. Finally, ERCOT and the PUCT are evaluating options to increase availability of other potential generation and demand-side resources.[42]

ERCOT is conducting a study to better understand current market dynamics and to assess obstacles that are delaying or preventing resource development. ERCOT has an energy-only market design, requiring developers of new generation to base expectations for revenue, primarily on their expectation of long-term, locational market prices. Delays in generation development are potentially a result of a combination of low market prices (due to low natural gas prices and significant wind generation development); reduced availability of capital for financing; and the general uncertainty associated with changing environmental regulations.

One of the largest near-term risks to resource adequacy in ERCOT is the legal action associated with the Cross-State Air Pollution Rule (CSAPR). In the event that the rule is reinstated during the 2012 summer season following legal review, resource owners in ERCOT may revert to their previously announced compliance plans, which in aggregate would result in a further reduction in available generation of approximately 1,200 to 1,400 MW. This would reduce both the Anticipated and Prospective Reserve Margins to 11.3 percent and would reduce the Existing-Certain and Net Firm Capacity Reserve Margin to 11.2 percent.

Demand

The 2011 summer actual peak demand set a new record for the ERCOT Region on August 3, 2011 of 68,416 MW. This peak demand was higher than the projected 2011 summer peak of 64,964 MW, due to extreme, above-normal temperatures in August. The summer of 2011 was noted as being the hottest summer on record of any state by the National Oceanographic and Atmospheric Administration (NOAA).[43] Ambient temperatures, particularly in the load centers that have experienced population growth, including Dallas/Ft. Worth, San Antonio and Houston, have been primary drivers of ERCOT's peak loads. Table 2 includes the demand forecasts for the 2011 and 2012 summers for the ERCOT Assessment Area.

Table 2: ERCOT Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	**63,531**	**64,605**	**1,074**	**1.69%**
Total Internal	**64,964**	**66,076**	**1,112**	**1.71%**

[40] http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/39948_31_721501.PDF
[41] Program to be renamed "Emergency Response Service (ERS)," effective June 1, 2012.
[42] http://www.ercot.com/mktrules/issues/nprr/426-450/450/index; and http://www.ercot.com/mktrules/issues/nprr/451-475/451/index
[43] http://www.noaanews.noaa.gov/stories2011/20110908_auguststats.html

ERCOT is also analyzing the impacts of localized incremental load-growth due to shale gas development near Ft. Worth and south of San Antonio. Transmission service providers are informing ERCOT of shale gas developments resulting in incremental additional loads, ranging upwards to 120 MW in several counties.

The demand forecast developed by ERCOT is based on economic and weather indicators and historical regional loads. The projected peak demand forecast for 2012 is 66,195 MW, an increase of 1.9 percent from the summer 2011 projected peak demand of 64,964 MW. The 2012 forecast is based on revised average (50/50) weather conditions, the calculation of which now includes extreme conditions experienced in 2011. A projected 90/10 peak demand forecast for 2012 is 67,492 MW which would not result in a new record system peak. There have been no significant changes in the forecasting process since the last summer's assessment.

Demand-Side Management

Load Resources (LRs)[44] providing Responsive Reserve Service,[45] an ancillary service provides averages of approximately 886 MW of dispatchable, contractually committed demand-side Load as a Capacity Resource during summer peak hours.[46] This set of loads is the only demand-side resource providing ancillary services to the ERCOT grid.

ERCOT's Emergency Interruptible Load Service (EILS), which is designed to be deployed in the late stages of a grid emergency, prior to shedding involuntary Firm load, represents demand-side Contractually Interruptible Demand. This service is being renamed the Emergency Response Service (ERS). Based on average EILS commitments during 2011, approximately 585 MW is expected to be available during the 2012 summer peak. These programs would reduce summer peak demand by a little over 2 percent.[47] Figure 20 and Table 3 present the demand response forecasted for the 2011 and 2012 summer peaks in the ERCOT Assessment Area.

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[44] See Section 3.17 and 3.18 of http://www.ercot.com/content/mktrules/nprotocols/current/03-030112_Nodal.doc; Previously referred to as Load Acting as Resources (LaaRs).

[45] Based on the most recently available data: http://www.ercot.com/content/mktrules/nprotocols/current/02-020111_Nodal.doc.

[46] The limit on LRs participation is in the process of being revised due to the increased overall procurement of responsive reserves. See http://www.ercot.com/content/mktrules/issues/nprr/426-450/434/keydocs/434NPRR-12_Board_Report_022112.doc for more information.

[47] Measurement and verification procedures for these programs are defined in the Performance Monitoring section of the ERCOT Protocols. http://www.ercot.com/content/mktrules/nprotocols/current/08-020111_Nodal.doc

Figure 20: ERCOT Demand Response

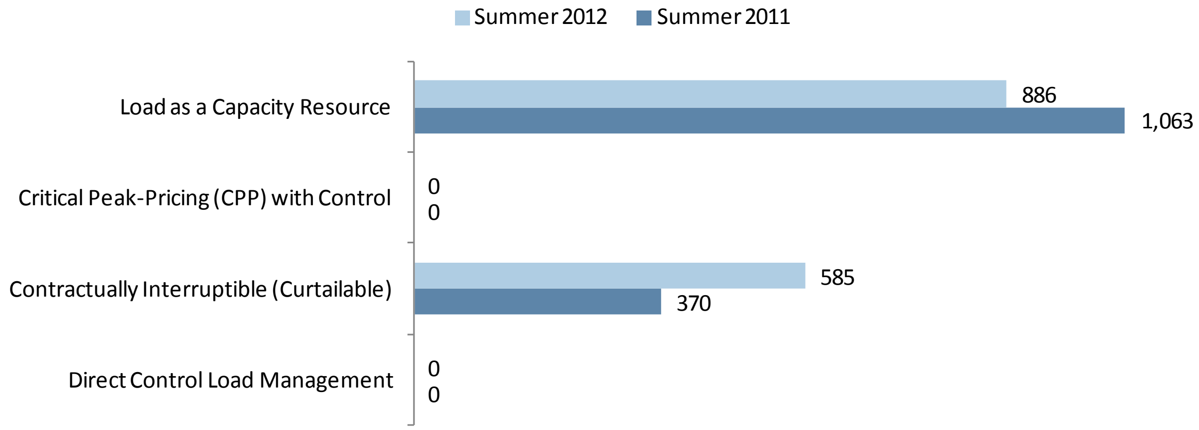

Table 3: ERCOT Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	0	0	0
Contractually Interruptible (Curtailable)	370	585	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	1,063	886	0
Total Demand Response	**1,433**	**1,471**	**0**
Percentage of Total Internal Demand	**2.21%**	**2.23%**	**0.00%**

In addition to these two demand response programs, several Transmission Service Providers (TSP) have individual contractual arrangements with loads that can respond to instructions to reduce total energy usage.

As stated before, ERCOT is actively pursuing market rule changes that will expand the number of resources that can participate in the newly formed ERS program, which will replace the current EILS program. ERCOT estimates that this change will increase the resources participating in the current EILS program by 130 to 200 MW. Additionally, ERCOT is working to better coordinate activation of load resources included in the TSP demand-response programs.

Utility savings, as measured and verified by an independent contractor, have exceeded utility goals.[48] In the latest assessment, these programs implemented after the restructuring of electric utilities in Texas have produced 1,666 MW of peak demand reduction and 4,110 GWh of electricity savings between 1999 and 2010.[49] This demand reduction is accounted for within the load forecast and only the expected incremental portion for the coming year, 119 MW, is included as a demand adjustment for the summer season.

48 http://www.texasefficiency.com/report.html

49 http://www.texasefficiency.com/files/EUMMOT_EEIP_June_2011.pdf.

Generation

Existing-Certain capacity in ERCOT, as reported by the generation owners, is 72,947 MW. The primary fuel sources for generation in ERCOT include natural gas (40,776 MW) and coal (17,071 MW). Since the prior season, 1,597 MW of on-peak generation capacity has been added or will return to service, consisting of 1,260 MW of gas generation (which includes 688 MW of mothballed units recalled into service), 275 MW of coal generation, 35 MW of wind generation (with nameplate capacity of 402 MW), and 27 MW of solar generation. Table 4 includes ERCOT forecasts for available resources during the 2011 and 2012 summer. Table 4 includes projections of ERCOT resources for the 2011 and 2012 summer.

Table 4: ERCOT Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	72,255	72,947
Future-Planned	260	123
Supply-Side Demand Response	1,433	0
Net Capacity Transactions	281	264
Anticipated	**74,229**	**73,334**
Existing-Other and Future-Other	0	0
Prospective	**74,229**	**73,334**

One 925 MW thermal generation project was expected to become available prior to the 2012 summer season. However, this project has been delayed, and is not expected to be available until March 2013.

Of the Existing-Certain capacity, 117 MW is biomass and 43 MW is solar. An expected 105 MW of biomass generation is included as Future-Planned resources. ERCOT counts these resources as available on-peak. There are 544 MW of hydro generation capacity in ERCOT; none of this capacity is considered expected on-peak. Of the 9,829 MW of existing wind generation capacity and 206 MW of Future-Planned wind generation capacity (expected on-line by June 2012), only 855 MW of Existing and 18 MW of Future-Planned is included in the expected On-Peak Resources respectively (the currently approved Effective Load Carrying Capability [ELCC] of wind resources in ERCOT is 8.7 percent).[50] A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 21 and Table 5.

[50] 2012 numbers are based on current filings: http://www.texasefficiency.com/files/EUMMOT_EEIP_June_2011.pdf.

Figure 21: ERCOT Renewable Generation

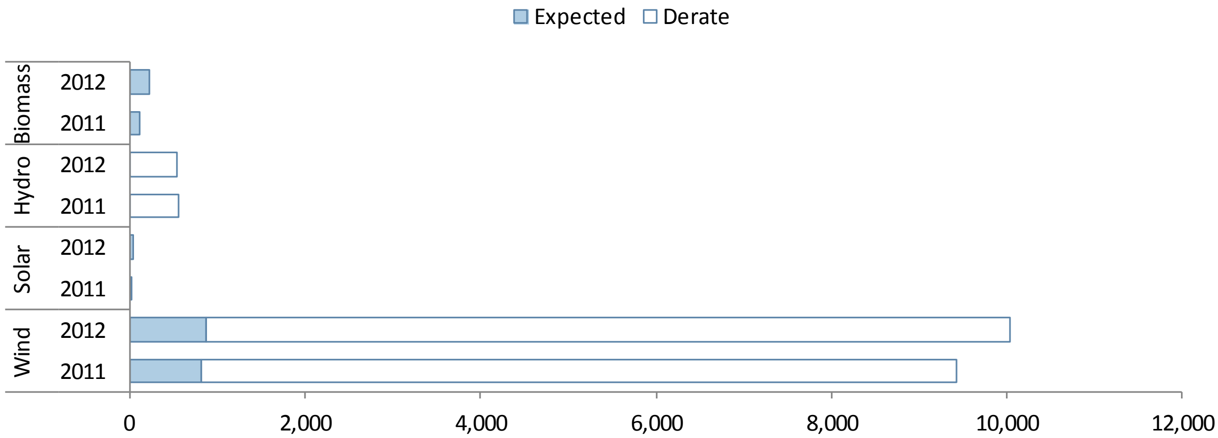

Table 5: ERCOT Renewable Generation

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	820	873	15	43	0	0	106	222
Derate	8,607	9,162	0	0	563	544	0	0
Nameplate	**9,427**	**10,035**	**15**	**43**	**563**	**544**	**106**	**222**

ERCOT has substantial experience maintaining operational reliability with significant and increasing levels of interconnected variable generation. Total available variable generation during the 2012 summer is not expected to be much higher than the output available during the 2011 summer. Using a combination of state-of-the-art wind generation forecasts, and flexible levels of ancillary services, ERCOT will effectively manage available wind and solar generation to support system reliability using current procedures. Continuing development of wind resources along the coast, which exhibit generation patterns that are more correlated with summer peak loads than wind sited in inland western portions of Texas, is also expected to increase the overall reliability benefit from wind generation. An evaluation of possible differences in a locational-based wind ELCC is in progress.

With only 43 MW of solar resources on the ERCOT transmission system, it is expected that the variability of these resources will not adversely affect the reliability of the grid. If solar generation becomes more prevalent in ERCOT, it will become necessary to develop an estimate of the ELCC of solar resources and a process for forecasting solar resources.

Less than 1 percent of the ERCOT generation capacity is hydro. These facilities are typically operated as run-of-river or planned release due to downstream needs and not operated specifically to produce electricity. As a result, limited availability of hydro generation should not have a reliability impact on the ERCOT Region this summer, even if drought conditions persist.

There are 1,946 MW of existing capacity that is mothballed (indefinitely idled) and considered inoperable (Existing-Inoperable). This capacity is not counted toward reserves during the 2012 summer season. Of this capacity, only 154 MW could return to service in 60 days or less. Since the last summer season, 1,131 MW of gas generation and 138 MW of petroleum coke fueled generation have returned to service, and 279 MW of additional gas generation has been put into mothballed (Existing-Inoperable) status. There is no Existing-Other generation in ERCOT.

No significant change is expected in the availability of behind-the-meter (or distributed) generation for the 2012 summer season. There are 2,962 MW of "switchable" generation that can operate in the ERCOT system or in the adjacent (not synchronously interconnected) regions. ERCOT counts all of this generation capacity as available, except for 317 MW, which is obligated to serve load outside of the ERCOT region.

Scheduled outages are expected for 240 MW of capacity during the month of August. Historically, there are approximately 710 MWs of scheduled outages and 3,080 MWs of forced outages (unplanned outages).[51] After the summer high load period, approximately 5,000 MW of scheduled outages for maintenance usually begin in September.

Capacity Transactions

The ERCOT Region is a separate Interconnection with only asynchronous ties to Southwest Power Pool (SPP) and Mexico's Comision Federal de Electricidad (CFE). As such, ERCOT does not share reserves with other Regions. There are two asynchronous ties between ERCOT and SPP with a total of 820 MW of transfer capability and three asynchronous ties between ERCOT and Mexico with a total of 280 MW of transfer capability. One of these ties (35 MW) between ERCOT and CFE is on an extended maintenance outage and is not scheduled to be available during the summer 2012 season. On-peak capacity transactions projected for the 2012 summer are included in Table 6.

Table 6: ERCOT Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	581	317	264
Expected	0	0	0
Total	**581**	**317**	**264**

The ERCOT Region does not rely on external resources to meet demand under normal operating conditions; however, under emergency support agreements, it may request external resources for emergency services over the asynchronous ties or by block transfer of discrete loads. For the summer 2012 season, ERCOT has 458 MW of imports from SPP and 123 MW from CFE. Of the total SPP imports, 48 MW are tied to a long-term contract for a purchase of Firm load from specific generation. The remaining imports of 410 MW from SPP and 123 MW from CFE represent one-half of the asynchronous tie transfer capability, included to reflect emergency support arrangements.[52] Several SPP members own 317 MW of a power plant located in the ERCOT Region, resulting in a Firm export of that amount from ERCOT to SPP. There are no known non-Firm contracts (signed, pending, etc.) that are known to be under negotiation or study.

Transmission

Several significant transmission improvements,[53] listed below, have been, or are expected to be completed throughout the ERCOT Region to meet reliability needs or reduce market congestion prior to,

[51] Per preliminary summer assessment located at: http://www.ercot.com/content/news/presentations/2012/SARA%20-%20Preliminary%20Summer%202012.pdf.

[52] This capacity is reduced from previous seasonal assessments due to the extended outage of the 35 MW Eagle Pass tie between ERCOT and CFE.

[53] As of March 2012.

or during the 2012 summer season.[54] Overall, 358 circuit miles of new 345 kV transmission have been added, with 15 additional circuit miles of upgrades. Additionally, 9 miles of 138 kV transmission have been added, with 260 circuit miles of upgrades.

Several significant system improvements associated with the transmission plan developed to serve the Competitive Renewable Energy Zones (CREZ) are scheduled to be in service by the 2012 summer season.[55] These projects are listed below:

- 345 kV double circuit from Bowman to Riley [85 circuit miles];
- 345 kV double-circuit from Sweetwater East to Central Bluff to Bluff Creek [91 circuit miles];
- 345 kV single-circuit from Twin Butte to Big Hill [31 circuit miles];
- 345 kV single circuit from Riley to Oklaunion [3.5 circuit miles];
- 345 kV double-circuit from Dermott Switch to Scurry County South [65 circuit miles].
- 345 kV double-circuit from Bell County East to TNP One [83 circuit miles];
- 345 kV switching station at Bell County East;
- 345/138 kV autotransformers constituting 4,500 MVA are scheduled to be installed at the Southeast Nacogdoches, Anna Switch, P. H. Robinson, Lewisville, Central Bluff, and Zenith substations

No delays are currently expected in meeting in-service dates of transmission projects needed for reliability. Some transmission outages may be scheduled during the 2012 summer season, but these outages are not expected to impact reliability. ERCOT performs outage coordination to maintain reliability for any planned transmission outages. As transmission constraints are identified, plans are developed to provide for preemptive or planned responses to maintain reliability.

Recent 345/138-kV autotransformer failures at the Venus Switch, Gilleland Creek and Salem substations are not expected to have an adverse impact on system reliability over the 2012 summer season. ERCOT is reviewing options with the affected transmission service providers to replace the autotransformers with spares, if available. The reason for these recent, non-related autotransformer failures is being evaluated at this time.

A voltage stability screening analysis to assess reactive power needs on the ERCOT system for the 2012 summer will be completed before the start of the summer season. Response of the network to NERC Category A, B and selected C contingencies will be reviewed and if necessary, actions planned will be provided.

Operations

For the 2012 summer season, no significant special operating studies have been conducted for the ERCOT Region and no unusual operating conditions that could impact reliability are anticipated. A voltage stability screening analysis to assess reactive power needs on the ERCOT system for the upcoming summer will be completed prior to the start of the season. Response of the network to NERC Category A, B and selected C contingencies test will be documented.

[54] Additional details on transmission projects can be found in the "Report on Existing and Potential Electric System Constraints and Needs" located on the following website: http://www.ercot.com/content/news/presentations/2012/2011%20Constraints%20and%20Needs%20Report.pdf.

[55] http://www.texascrezprojects.com/default.aspx.

For variable resources, ERCOT will use established operational procedures during the 2012 summer season. ERCOT has implemented a wind power forecasting system to allow ERCOT Independent System Operators (ISO) to identify and take appropriate action when wind resource schedules may not track expected changes in wind output. ERCOT has also implemented 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. In addition, ERCOT evaluates the impact of increased installed wind generation on ancillary services requirements on an ongoing basis.[56]

Resources are expected to be tight for 2012 summer season and beyond. ERCOT and the PUCT are evaluating all potential generation and demand-side resources in order to minimize the potential for Firm load loss during emergency conditions. It is expected that emergency conditions, including Energy Emergency Alerts (EEA), will occur during the 2012 summer season. Recently 688 MWs of mothballed generation signaled a return to service prior to the start of the summer season. Barring a repeat of extreme heat conditions similar to those encountered during the 2011 summer, elevated levels of unit outages and other issues noted in the Vulnerability Assessment section below, there should be sufficient reserves to avoid the need for rotating outages to maintain system reliability.

ERCOT regularly monitors the availability of surface water resources for cooling at generation facilities. Recent analyses indicate that it is unlikely that there will be any impact to resource availability over the upcoming 2012 summer season due to drought conditions. The effects of any limitations that arise will be mitigated through the procurement of ancillary services, including Reliability Unit Commitment (RUC)[57] deployments, or emergency procedures, if required. At this time, these issues do not constitute a significant reliability concern for the Region.

There are no anticipated reliability concerns for the summer season resulting from over generation during low demand at current levels of wind generation and overall resource mix.

Currently, ERCOT limits the participation of dispatchable, contractually committed Demand-Side Load as a Capacity Resource (referred to as Load Resources in ERCOT Region). This limitation allows up to 50 percent (1,150 MW limit) of the Responsive Reserve (RRS) Ancillary Service,[58] which can be deployed in response to large frequency excursions (below 59.7 Hz) or during system emergencies. There are approved changes to the ERCOT Protocols, increasing RRS by 500 MW, which may impact the Load Resource participation. ERCOT is performing a technical review of the RRS change with regards to the Load Resource impact.[59] ERCOT procures these Load Resources across all hours to address system conditions at all times – not just during peak periods. ERCOT's monitoring and testing programs ensure that these Load Resources will perform when called. The status of Load Resources providing Ancillary Services is monitored in real–time, via 2-second telemetry.

ERCOT procures Emergency Interruptible Load Service (EILS) (referred to by NERC as Demand-Side Contractually Interruptible Demand). These resources are monitored by using after-the-fact metering and are subject to payment reductions and suspension from the program for failing to meet availability

[56] http://www.ercot.com/content/mktinfo/dam/kd/ERCOT%20Methodologies%20for%20Determining%20Ancillary%20Service%20Requir.zip.
[57] http://www.ercot.com/content/mktrules/nprotocols/current/02-020111_Nodal.doc.
[58] http://www.ercot.com/content/mktrules/nprotocols/current/02-020111_Nodal.doc.
[59] http://www.ercot.com/mktrules/issues/nprr/426-450/434/index.

requirements. Both Load Resources and EILS products are subject to annual unannounced load-shed testing, to be followed by an additional test if the first is unsuccessful. A second consecutive unsuccessful test subjects the resource to suspension.

There are no restrictions on the number of deployments in a day for Load Resources procured in the day-ahead Ancillary Services market. EILS Loads are procured for four-month contract periods and are limited to a maximum of eight hours of deployments over those months – with the proviso that the Loads may not return to service until released by ERCOT operations.

Given the recent stay in the implementation of the Cross-State Air Pollution Rule (CSAPR) issued by the D.C Circuit Court of Appeals, no environmental regulations are expected to have an adverse impact on system reliability over the 2012 summer season. Further discussion of the implications of potential Court action is provided in the Vulnerability Assessment.

There are no other anticipated unusual operating conditions that could significantly affect reliability during the 2012 summer season.

Vulnerability Assessment

The single or combined impacts of the following risk factors could lead to inadequate supply in the ERCOT Region during the 2012 summer: an extremely hot summer resulting in load levels significantly above the forecast; above-normal unit forced outage rates; extended maintenance outages; CSAPR-based idling of units; and financial difficulties of some generation owners creating challenges in obtaining fuel from suppliers.

If such an event occurs, ERCOT will implement actions described in Section 5.6 of the ERCOT Protocols[60] and Section 4 of the ERCOT Operating Guides,[61] which describe EEAs and procedures for use of interruptible load, voltage reductions, procuring emergency energy over the asynchronous ties, and ISO-instructed demand response.

Currently available information indicates that it is unlikely that water unavailability will limit generation resources during the 2012 summer season. No significant increases in variable generation are expected prior to, or during the 2012 summer season; no significant long-term generator outages are expected, and it is unlikely that there will be availability issues associated with demand response programs established in the ERCOT Region.

Gas curtailments do not typically occur in the summer season. Natural gas supply and transportation issues are typically of more concern during the winter season, due to competition with home heating for pipeline and distribution capacity. ERCOT has recently completed an analysis of potential impacts of gas transportation limitations on grid reliability. This study found that any such impacts are unlikely and expected to be minor.[62] Coal transportation issues are not expected to pose a reliability impact in ERCOT this summer. Overall fuel supply issues are not expected to impact 2012 summer resource availability. Finally, no new System Protection Schemes (SPS) or Remedial Action Plans (RAP) has been added since the 2011 summer season.

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

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

[62] http://www.ercot.com/content/meetings/board/keydocs/2012/0221/Item_06_-_Gas_Risk_Study.zip.

ERCOT continues to review the potential impacts of changes in environmental regulations on the expected availability of generation resources in the upcoming seasons. Information from the resource owners regarding compliance strategies and unit availability are aggregated to develop compliance scenarios which are then analyzed for impacts to resource adequacy and system reliability using the established ERCOT planning models and processes, as needed. Throughout the past year, ERCOT has reviewed the potential impacts of the several proposed and final environmental rules, including the Mercury and Air Toxics Rule (MATR), and the Cross-State Air Pollution Rule (CSAPR). Reports describing the findings of these studies are available on the ERCOT website.[63] Of the rules and regulations analyzed, only the CSAPR was found to potentially affect generation availability during the 2012 summer season. This rule was stayed by the D.C. District Court of Appeals on December 30, 2011, prior to implementation. Had it not been stayed by the Court, two coal generation units, totaling 1,130 MW, were scheduled to be idled, starting on January 1, 2012, and remain unavailable throughout the 2012 summer season, as a result of compliance requirements of the CSAPR. As a result of the stay imposed by the Court, these plants were not idled and are now expected to be available during the 2012 summer season. The recent amendments to the CSAPR – which, in part, propose an increase to the number of emission allowances allocated to Texas coal units – have unknown impacts on whether or not these two coal plants would be idled if the rule is reinstated, following further review by the Court. As a result of the stay by the Court, it is not expected that extended maintenance outages will be required to install environmental controls to maintain compliance during the 2012 summer season.

Given the expected reserve margin in the ERCOT Region for the 2012 summer season (below the minimum Reference Margin Level), unavailability of one or more large thermal generators due to the compliance requirements of the CSAPR or, in fact, for any reason (such as an extended maintenance outage), would increase the risk of emergency conditions during 2012 summer peak load hours, and could necessitate rotating outages in the event of extreme heat or significant other generation unit outages.

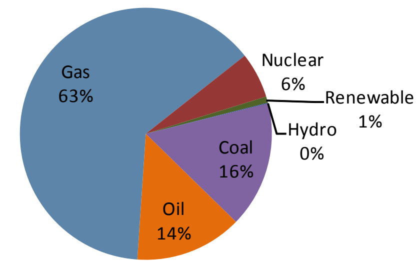
ERCOT is also conducting a study to better understand current market dynamics and to assess obstacles that are delaying or preventing resource development. ERCOT has an energy-only market design, requiring developers of new generation to base revenue expectations primarily on their expectation of long-term, locational market prices. Delays in the development of generation are potentially a result of a combination of low market prices (due to low natural gas prices and significant wind generation development); reduced availability of capital for financing; and uncertainty associated with changing environmental regulations.

[63] http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf; and http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf.

FRCC

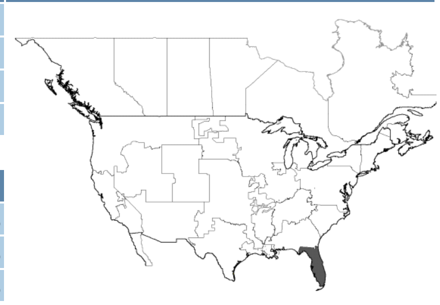
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	53,096	-
Future-Planned	0	-
Supply-Side Demand Response	3,131	-
Net Capacity Transactions	2209	-
Anticipated	**61,115**	**27.84%**
Existing-Other and Future-Other	0	-
Prospective	**61,115**	**27.97%**
Reference Margin Level	0	**15.00%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**42,960**	**42,430**
Demand-Side Demand Response (2012)	-	3,183
Supply-Side Demand Response (2011)	3,131	-
Total Internal	**46,091**	**45,613**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	42,960	-1.23%
Actual Peak Demand	46,091	-7.94%
All-Time Summer Peak Demand (August 10, 2007)	46,739	-9.22%

Note: Additional information regarding the methods and assumptions used in the development of the FRCC seasonal assessment can be found in Appendix I and on the NERC website.[64]

Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the FRCC Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The Reserve Margins for the FRCC Assessment Area are based on Anticipated resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

A net total of 650 MW of capacity will be added during the 2012 summer. According to the FRCC demand forecast, Total Internal Demand has increased from 44,798 MW to 45,613 MW since the 2011 summer. This equates to an annual growth rate of 1.8 percent.

Planning Reserve Margins

The FRCC is projecting adequate Reserve Margins during the 2012 summer. A 15 percent Reserve Margin criteria[65] is required by the Florida Public Service Commission for the FRCC Region for all planning horizons. Based on the expected load and generation capacity, the calculated Anticipated Capacity Resources Reserve Margin for the summer of 2012 is 27.8 percent when Load Management and Interruptible loads are treated as a demand reduction. Table 7 includes the 2011 and 2012 Reserve Margins for the FRCC Assessment Area.

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[64] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

[65] 20 percent for Investor Owned Utilities.

Table 7: FRCC Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	15.00%	15.00%
Existing-Certain & Net Firm Transactions	32.60%	29.59%
Anticipated	32.60%	27.84%
Prospective	32.60%	27.97%

Factors impacting the summer Reserve Margin include a 3 to 4 year period of weak economic demand resulting in more than adequate Reserve Margins. The restrained mobility of relocations to the area has served to reduce forecasted customer growth and projected peak demands over prior forecasts. A rebound in the economy could potentially increase the demand, energy, and load projections that could result in realignment with previous projections.

There exists the possibility that the passage of pending environmental and/or regulatory regulations could lead to timing challenges in the retrofitting and/or building of replacement generation. The forced shutdown of existing generation from these pending activities could cause unscheduled outages of generation, possibly resulting in a decrease in Reserve Margins.

Demand

Last year's peak demand forecast for the summer of 2011 was 46,091 MW, which was 1,293 MW (2.9 percent) above the 2011 actual demand of 44,798 MW.

The FRCC is forecasted to reach its 2012 summer non-coincident peak Total Internal Demand of 45,613 MW in August, which represents a projected demand increase of 1.8 percent above the actual 2011 summer demand of 44,798 MW. This projection for the 2012 summer is consistent with historical weather-normalized FRCC demand growth and is 1.0 percent lower than last year's summer forecast of 46,091 MW. The small decrease in the 2012 projected summer peak demand is attributed to lower expected consumption and economic activity versus the previous projection. Table 8 includes the 2011 and 2012 Reserve Margins for the FRCC Assessment Area. Table 8 includes the demand forecasts for the 2011 and 2012 summers for the FRCC Assessment Area.

Table 8: FRCC Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	42,960	42,430	-530	-1.23%
Total Internal	46,091	45,613	-478	-1.04%

Load growth across individual Load Serving Entities (LSE) in the Region is proportional with the level of load growth seen across the FRCC Assessment Area.

Demand-Side Management

The 2012 summer Net Internal Demand forecast includes the effects of 3,183 MW of potential demand reductions from the use of load management (2,563 MW) and interruptible demand (620 MW). Demand response within FRCC is treated as a "demand reduction" and not as a capacity resource. Demand reduction is used primarily to shave the peak demand. Figure 22 and Table 9 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the FRCC Assessment Area.

Figure 22: FRCC Demand Response

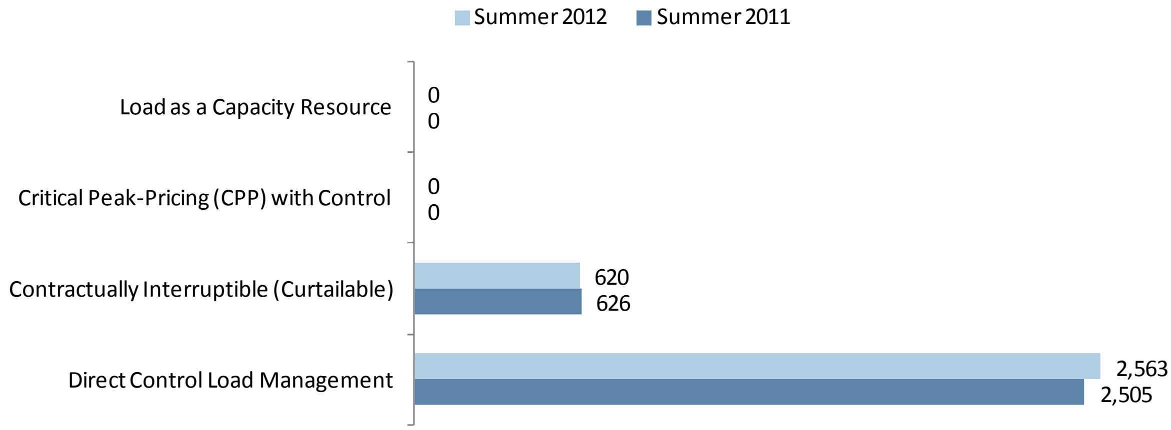


Table 9: FRCC Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	2,505	2,563	0
Contractually Interruptible (Curtailable)	626	620	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	0	0	0
Total Demand Response	**3,131**	**3,183**	**0**
Percentage of Total Internal Demand	**6.79%**	**6.98%**	**0.00%**

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

The Florida Public Service Commission approved updated, more aggressive numeric Demand-Side Management (DSM) goals in 2010 for participating entities in the state, of which some have begun implementation. Financial incentives have also been made available to various utilities with DSM achievements that exceed Commission-approved goals. It is projected that over the coming decade, Demand Response will increase at an average annual growth rate of about 1.5 percent.

Generation

The FRCC Region counts on 53,096 MW of Existing-Certain resources, of which 44 MW are hydro and 334 MW are Biomass. Potential solar capacity is projected to be 55 MW; however most of this capacity is de-rated with approximately 7.8 MW considered as a Firm resource, available during peak demand, with the remainder being used as an energy-only resource. Derated hydro capacity will be 11 MW, while Existing-Other merchant plant capability of 183.4 MW is potentially available as future resources of FRCC members and others. There are a total of 2,821 MW of Existing-Inoperable resources for the 2012 summer. Table 10 includes projections of FRCC resources for the 2011 and 2012 summer.

Table 10: FRCC Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	55,775	53,096
Future-Planned	0	-745
Supply-Side Demand Response	3,131	0
Net Capacity Transactions	2,209	1,890
Anticipated	**61,115**	**54,241**
Existing-Other and Future-Other	0	56
Prospective	**61,115**	**54,297**

There are no retirements planned for the upcoming season, however, 1,780 MW of generation is being temporarily reactivated from Inactive Reserves[66] to function as replacement capacity for 1,652 MW of generation planned for capacity upgrades prior to the summer season. A net projected capacity of 881 MW will be added prior to the beginning of the summer season, with 745 MW being temporarily removed during August for other planned unit upgrades. These activities are not expected to have an impact on generation scheduled to serve load. There are 849 MW of capacity not included in the summer forecast due to a long-term outage; however, this capacity is scheduled to be returned to service in late 2014. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 23 and Table 11.

Figure 23: FRCC Renewable Generation

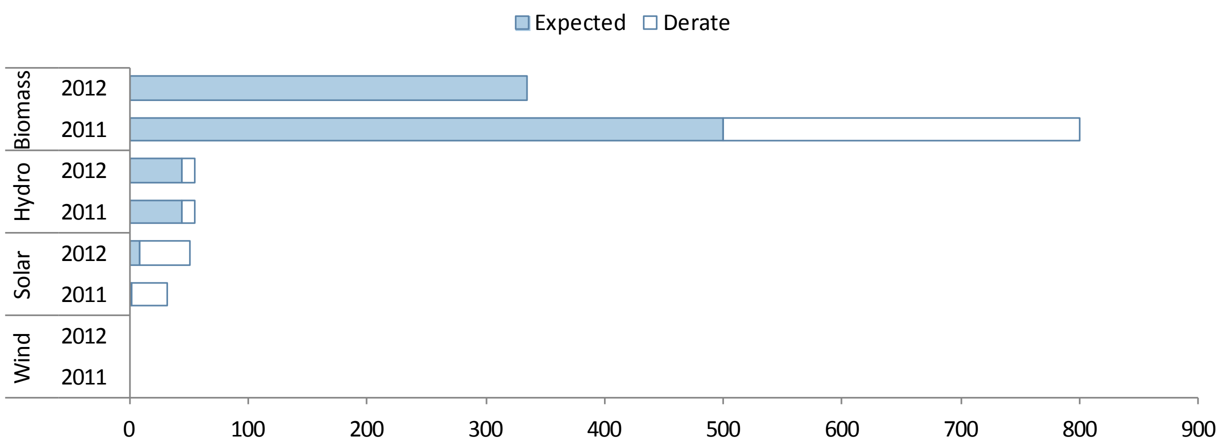


Table 11 FRCC Renewable Generation

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	0	0	1	8	44	44	500	334
Derate	0	0	30	44	11	11	300	0
Nameplate	**0**	**0**	**31**	**51**	**55**	**55**	**800**	**334**

[66] IEEE 762: Inactive Reserves – "the state in which a unit is unavailable for service but can be brought back into service after some repairs in a relatively short duration of time." FRCC does include Inactive Reserves capacity in the calculation of Reserve Margins when this generation is not in commercial service.

Capacity Transactions

There are 1,197 MW of generation under Firm contract, available to be imported into the Region from the SERC-SE Assessment Area throughout the summer season, and another 836 MW of member-owned generation, which is dynamically dispatched out of the SERC-SE Assessment Area. These purchases have Firm transmission service to ensure deliverability into the FRCC Region.

The FRCC Region has 143 MW of generation under Firm contract to be exported during the summer into the SERC-SE Assessment Area through 2020. These sales have Firm transmission service to ensure deliverability. On-peak capacity transactions projected for the 2012 summer are included in Table 12.

Table 12: FRCC Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	2,033	143	1,890
Expected	0	0	0
Total	**2,033**	**143**	**1,890**

Non-Firm resources or Expected transactions are not included in the assessment for the calculation of reserve margins. The FRCC Region does not rely on external resources for emergency imports and reserve sharing. However, there are emergency power contracts in place between SERC members and FRCC entities.

Transmission

Currently the FRCC Region expects to have three Bulk Electric System (BES) transmission facilities staggered out of service during the 2012 summer season. These outages were studied as part of the FRCC Operational Seasonal Study and are not anticipated to affect reliability. Additionally, no concerns were identified for meeting the target in-service dates of new projects that may impact system reliability during the 2012 summer season.

The FRCC Region has not identified any specific projects that are needed to maintain or enhance reliability during the 2012 summer season. Additions to the FRCC Bulk Power System are primarily related to expansion in order to serve forecasted growing demand and maintain the reliability of the Bulk Power System in the longer-term planning horizon.

Operations

FRCC expects the BES to perform adequately over various system operating conditions with the ability to deliver the resources to meet the load requirements at the time of the summer peak demand. The FRCC performed a Summer Transmission Assessment and Operational Seasonal Study to assess the adequacy and robustness of the FRCC BES under expected 2012 summer peak load and under anticipated system conditions (taking into account generation and transmission maintenance activities). This regional assessment and operational study analyzed the performance of the transmission system under normal conditions, single contingency events, and selected multiple contingency events determined relevant by pass studies. The results were coordinated and peer-reviewed by the FRCC's Operations Planning Working Group to ensure the BES performs adequately throughout the summer timeframe. The study results demonstrated that potential thermal and voltage conditions exceeding the applicable screening criteria could be successfully mitigated under normal conditions, single contingency events, and selected multiple contingency events. The transmission system within the FRCC Region is expected to perform reliably for the anticipated 2012 summer peak season system operating conditions.

No new operating procedures are needed as result of integration of variable resources for the summer 2012. Minimum demand and over generation scenarios typically do not occur under normal conditions due to limited variable resources within the FRCC Region.

Demand-Side Management load control programs within the FRCC are treated as "demand reduction" and not as a capacity resource. Based on past experience, demand reduction is used on a limited basis and is expected to be fully available when called upon. The FRCC does not anticipate any issues with the availability of demand reduction during the 2012 summer season.

Based on the FRCC Summer Transmission Assessment and Operational Seasonal Study, no unusual operating conditions are expected to impact reliability for the upcoming 2012 summer.

Vulnerability Assessment

Three 800 MW class units are scheduled to be unavailable during some period of the 2012 summer season (one continuous, others will be staggered). Based on the FRCC Summer Transmission Assessment and Operational Seasonal Study, the unavailability of these units is not anticipated to cause any reliability concerns. The FRCC does not foresee any issues associated with long-term (extended) drought conditions, the unavailability of demand resources or as a result of increase in variable generation.

Following the 2011 summer season, two new permanent Special Protection Systems (SPS) were installed within the FRCC Region. The SPSs were designed to protect BES facilities under certain generation dispatch scenarios and specific multiple contingency events.

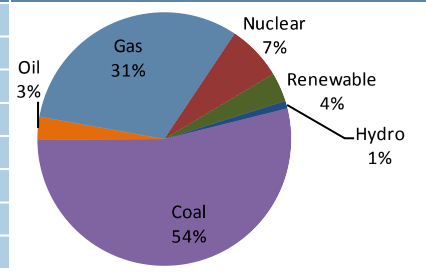
The FRCC Region is not anticipating any reliability impacts as result of environmental and/or regulatory restrictions for the summer of 2012. The Environmental Protection Agency (EPA) did issue the Cross State Air Pollution Rule (CSAPR) on August 8, 2011. This rule would require the FRCC region to reduce NOx emissions by 30 percent of 2010 levels during the Ozone season from May 1 through September 30, starting in the summer of 2012. However, a large number of parties have petitioned for judicial review and a stay of the CSAPR. On December 30, 2011 the D.C. Circuit Court of Appeals did issue a stay of the CSAPR until all the challenges to the rule are resolved. The Florida Electric Coordinating Group's (FCG) Environmental sub-committee is not anticipating CSAPR to take effect prior to 2013.

For the 2012 summer season, no concerns are anticipated due to a limited fuel supply within the FRCC Region. There is no fuel availability or supply issues identified at this time. Based on recent studies, current fuel diversity, alternate fuel capability and fuel study results, the FRCC does not anticipate any fuel transportation issues affecting resource capability during the 2012 summer season.

MISO

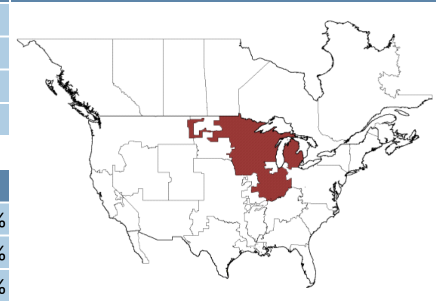
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	107,107	-
Future-Planned	120	-
Supply-Side Demand Response	3,523	-
Net Capacity Transactions	1,655	-
Anticipated	**113,952**	**28.65%**
Existing-Other and Future-Other	13,347	-
Prospective	**127,299**	**43.72%**
Reference Margin Level	-	**16.70%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**91,753**	**88,573**
Demand-Side Demand Response (2012)	-	4,529
Supply-Side Demand Response (2011)	7,819	-
Total Internal	**99,572**	**93,102**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	91,753	-3.47%
Actual Peak Demand	96,755	-8.46%
All-Time Summer Peak Demand (July 31, 2006)	109,157	-18.86%

Note: Additional information regarding the methods and assumptions used in the development of the MISO seasonal assessment can be found in Appendix I and on the NERC website.[67]

Assessment Area Highlights

MISO's membership has changed since the 2011 summer. Duke Energy Ohio and Duke Energy Kentucky consolidated into the PJM RTO on January 1, 2012, removing approximately 5,700 MW of load and generation from MISO's footprint. Currently, MISO's membership consists of 40 Transmission Owners and 98 non-transmission owners. MISO's scope of operations encompasses 49,641 miles of transmission over 11 states and one Canadian province. MISO's Energy and Operating Reserves market includes 363 market participants serving over 38.9 million people.

MISO continues to establish reserve margin requirements for its members. For planning year 2012 MISO's System Installed Generation Planning Reserve Margin (PRMSYSIGEN) requirement on a MISO coincident load basis is 16.7 percent. The PRMSYSIGEN for the MISO Assessment Area is based on Net Internal Demand and Anticipated Capacity Resources. The Anticipated Reserve Margin exceeds MISO's Reserve Margin Requirement during 2012 summer season.[68]

In addition to the existing capacity of 121,994 MW for the expected peak month of July 2012, a total of 350 MW of nameplate wind capacity is anticipated to be added between the 2012 summer months of August and September. According to the MISO's demand forecast for July 2012, Total Internal Demand has decreased from 96,755 MW[69] to 93,103 MW since the 2011 summer. However, the actual Total

[67] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

[68] Forecasts in this report reflect MISO load and resources which are not included in MAPP's Assessment Area.

[69] Actual Integrated Peak Load of 103,621 MW (July 20th hour-ending 17:00) decreased approximately 5.5 percent due to Duke's exit and approximately an additional 1.0 percent due to load shared between MISO and MAPP Planning Coordinator boundaries.

Internal Demand for the 2011 summer was a 90/10 load. For an equivalent comparison, with a 90/10 2012 summer load forecast, Total Internal Demand has actually increased from 96,755 MW to 98,377 MW. This equates to an annual summer growth rate of 1.7 percent.

Planning Reserve Margins

For planning year 2012 MISO's System Installed Generation Planning Reserve Margin (PRMSYSIGEN) requirement on a MISO coincident load basis is 16.7 percent.[70]

For the summer of 2012 the Anticipated and Prospective Reserve Margins are 28.7 percent and 43.7 percent, respectively, both exceeding MISO's Reference Margin Level. Some contributing factors to adequate reserve margin levels through the 2012 summer are provided. Table 13 includes the 2011 and 2012 reserve margins for the MISO Assessment Area.

Table 13: MISO Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	15.00%	16.70%
Existing-Certain & Net Firm Transactions	20.62%	26.77%
Anticipated	20.62%	28.65%
Prospective	33.99%	43.72%

A regional benefit of MISO is that the respective members do not experience peak during the same period. This estimated diversity of the MISO Assessment Area is 4.61 percent of MISO's Unrestricted Non-Coincident Peak Load. For more information on how MISO calculates Load Diversity, please see the 2012 LOLE study report. MISO's estimated diversity contributes 6.2 percentage points to the Anticipated Reserve Margin.

MISO Market Participants are forecasted to offer 4,529 MW of Demand-Side programs (Interruptible Load, IL and Direct Control Load Management, DCLM) in the market to serve MISO load, contributing 5.5 percentage points to the Anticipated Reserve Margin.

MISO Market Participants are forecasted to offer 3,523 MW of Supply-Side Load as a Capacity Resource, served by behind-the-meter generation, in the market to serve MISO load, contributing 3.7 percentage points to the Anticipated Reserve Margin.

Due to MISO's substantial generation resource fleet, MISO's Existing-Certain Capacity Resources expected to be available during the 2012 summer season's peak exceed even those resources procured through MISO's Module E process to meet the 16.7 percent reserve margin requirement. This excess capacity amounts to 6,333 MW, contributing 6.5 percentage points to the Anticipated Reserve Margin.

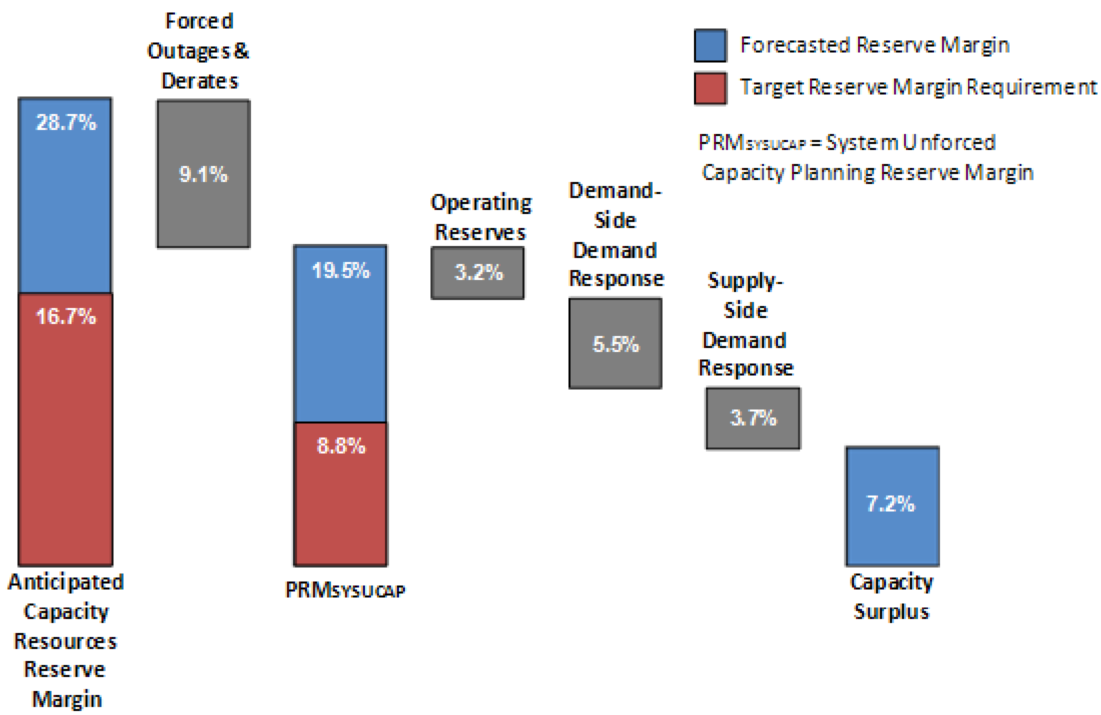
Entities outside of MISO are forecasted to offer 3,073 MW of external capacity in the market to serve MISO load. In addition to these Firm Full-Responsibility Purchases, through Module E, MISO expects 1,934 MW of additional Non-Firm imports. Net Capacity Transactions are expected to amount to 3,202 MW during the 2012 summer peak, contributing 3.3 percentage points to the Anticipated Reserve Margin.

[70] For more information regarding how MISO establishes requirements please see the 2012 LOLE study report: https://www.midwestiso.org/Library/Repository/Study/LOLE/2012%20LOLE%20Study%20Report.pdf.

In addition to the reserve margins discussed in previous paragraphs, MISO calculates a System Unforced Capacity Planning Reserve Margin (PRMSYSUCAP) which takes into account MISO's forced outage rate and Planning Reserves prior to Emergency Operating Procedures (EOPs) that anticipates the reserve level under normal operating conditions during the 2012 summer.[71]

To forecast forced outages and derates, MISO applies each unit's 5 year average Equivalent Forced Outage Rate on Demand (EFORd), from Generator Availability Data System (GADS), to their respective summer ratings. Under normal operating conditions, MISO Demand Response (Demand-Side IL, Demand-Side DCLM, Supply-Side Load as a Capacity Resource, BTMG) are inaccessible to the operators. MISO must initiate a level 2 Maximum Generation Emergency Event to access Demand Response. Also, MISO's Operating Reserves of approximately 2,400 MW are only utilized given a level 3 Event. The waterfall chart below, Figure 24, shows the progression of reserve levels from Anticipated Reserve Margin to Planning Reserves prior to EOPs.

Figure 24: MISO 2012 Forecasted Summer Peak Reserve Margin Criteria



It is always possible that a combination of high loads due to adverse weather, a lack of wind generation, high rate of outage, lack of external support, lack of Demand Response, etc could result in curtailment of Firm load. Such a curtailment is considered to be a low probability event for this summer, since the projected reserve margin far exceeds the established minimum requirement, external support and demand response have Firm contracts to serve MISO load this summer through the Module E process, and fuel scarcity is not projected to be an issue. For further risk analysis, please refer to Operations and Vulnerability Assessment sections 8 and 9 respectively of this report.

[71] Normal operating conditions refers to MISO's operation of the grid without initiating Emergency Operating Procedures. This margin is calculated for the 2012 summer season by removing 10,052 MW of EOPs, which are a component of the PRMSYSUCAP.

Demand

During the 2011 summer season, MISO experienced an instantaneous peak load[72] of 103,975 MW and settled peak of 103,621 MW on July 20, 2011 (hour ending 17:00 EST). For consistency with other reporting entities, adjusting last year's settled load for the Duke Energy Ohio and Kentucky (DEOK) departure and for load in the MAPP Assessment Area, as an adjacent Planning Coordinator to MISO, the settled load of 96,755 MW is being used for the purposes of this analysis. Table 14 includes the demand forecasts for the 2011 and 2012 summers for the MISO Assessment Area.

Table 14: MISO Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	**91,753**	**88,573**	**-3,180**	**-3.47%**
Total Internal	**99,572**	**93,102**	**-6,470**	**-6.50%**

Demand values, as reported by Network Customers, are weather-normalized (50/50, forecasts). An unrestricted non-coincident peak demand is created on a regional basis by summing the coincident monthly forecasts for the individual Load Serving Entities (LSE) in the larger regional area of interest. In MISO's Module E construct, the final Module E forecast is due by June 1, 2012. To capture the uncertainty around final and initial Module E forecast that is used in assessment reports, MISO calculated the difference between 2011 initial and final Module E forecast and prorated MISO's Total Internal Demand forecast to capture this uncertainty. This is a new enhancement to MISO's forecasting technique for the 2012 summer season. Similar to last summer, a load diversity factor was calculated by observing the individual peaks of each Local Balancing Authority (BA) and comparing these values against the system peak. This produced an estimated diversity of 4,500MW.

According to the MISO demand forecast for the peak month of July 2012, Total Internal Demand has decreased from 96,755 MW to 93,103 MW, compared to the 2011 summer. However, the actual Total Internal Demand for the 2011 summer was comparable to a 90/10 load, based on last summer's 50/50 forecasts. For an equivalent comparison, with a 90/10 scenario applied to the 2012 summer load forecast, Total Internal Demand has actually increased from 96,755 MW to 98,377 MW. This equates to an annual summer growth rate of 1.7 percent.

Demand-Side Management

MISO bases its resource evaluation on the actual market peak. MISO currently separates Demand-Side Demand Resources into two categories: Interruptible Load (IL) and Direct Controlled Load Management (DCLM). IL of 3,506 MW for this assessment is the magnitude of customer demand (usually industrial) that – in accordance with contractual arrangements – can be interrupted at the time of peak by direct control of the system operator (remote tripping), or by action of the customer, at the direct request of the system operator. DCLM of 1,023 MW (one percent of Total Internal Demand) for this assessment is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for "peak shaving." The Resource Adequacy processes as set forth in Module E of MISO's tariff acts as the measurement and

[72] The instantaneous load is the highest value metered during the peak hour, while the settled load is the integrated average value of metered data over the peak hour.

verification tool for Demand Response. Figure 25 and Table 15 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the MISO Assessment Area.

Figure 25: MISO Demand Response

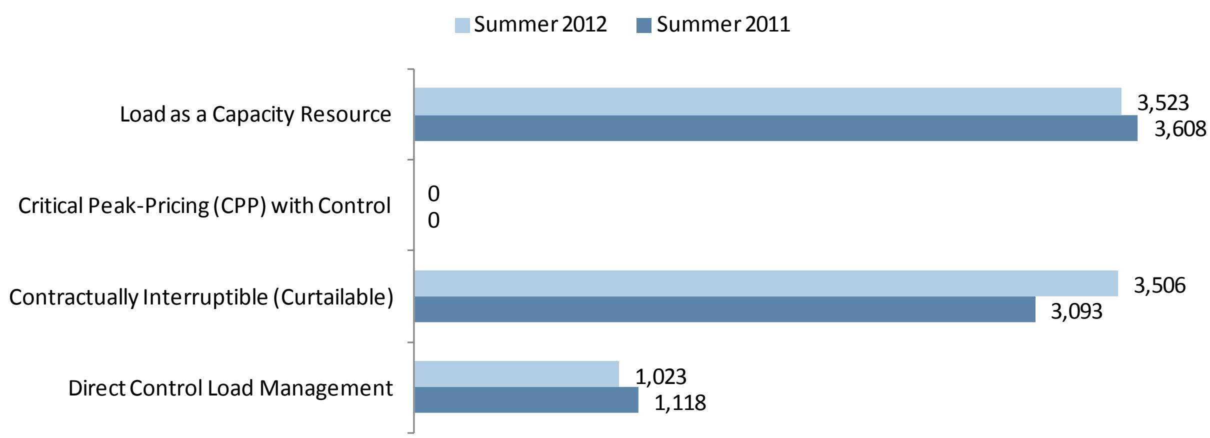


Table 15: MISO Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	1,118	1,023	0
Contractually Interruptible (Curtailable)	3,093	3,506	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	3,608	0	3,523
Total Demand Response	**7,819**	**4,529**	**3,523**
Percentage of Total Internal Demand	**7.85%**	**4.86%**	**3.78%**

Generation

MISO's projected Existing-Certain, Existing-Other, and Existing-Inoperable capacities are 107,107 MW, 13,347 MW, and 1,540 MW respectively, totaling 124,994 MW of Existing Capacity Resources projected to be available for the forecasted peak month of July 2012. The three primary fuel sources for MISO are coal, gas and nuclear. Coal units will account for 56.1 percent, while gas and nuclear Units will be 23.2 percent, and 7.9 percent respectively. Since last summer season, 9 new wind resources have come online with a total nameplate rating of 691 MW, of which, 102 MW is considered Existing-Certain for the 2012 summer season.

MISO anticipates 120 MW of Future-Planned resources consisting of facility upgrades to bring an additional 82MW on line from an existing coal facility and an additional 32MW from a new coal generator to be added leading up to the 2012 summer and 210 MW of Future-Planned resources consisting of interconnection of wind capacity to be added during the 2012 summer season. Table 16 includes projections of MISO resources for the 2011 and 2012 summer.

Table 16: MISO Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	107,391	107,107
Future-Planned	0	120
Supply-Side Demand Response	7,819	3,523
Net Capacity Transactions	4,894	1,655
Anticipated	**120,104**	**113,952**
Existing-Other and Future-Other	13,309	13,347
Prospective	**133,413**	**127,299**

The largest negative impact to MISO's Existing capacity since the prior season was due to the departure of DEOK from MISO, effective January 2012. This directly reduced MISO's Existing-Certain capacity by 5,070 MW.

In addition to the 107,107 MW of Existing-Certain capacity, MISO plans to use BTMG under Firm contract through Module E to serve MISO load this summer. MISO projects 3,523 MW of BTMG as Supply-Side Demand Response to be available during the 2012 summer season. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 26 and Table 17.

Figure 26: MISO Renewable Generation

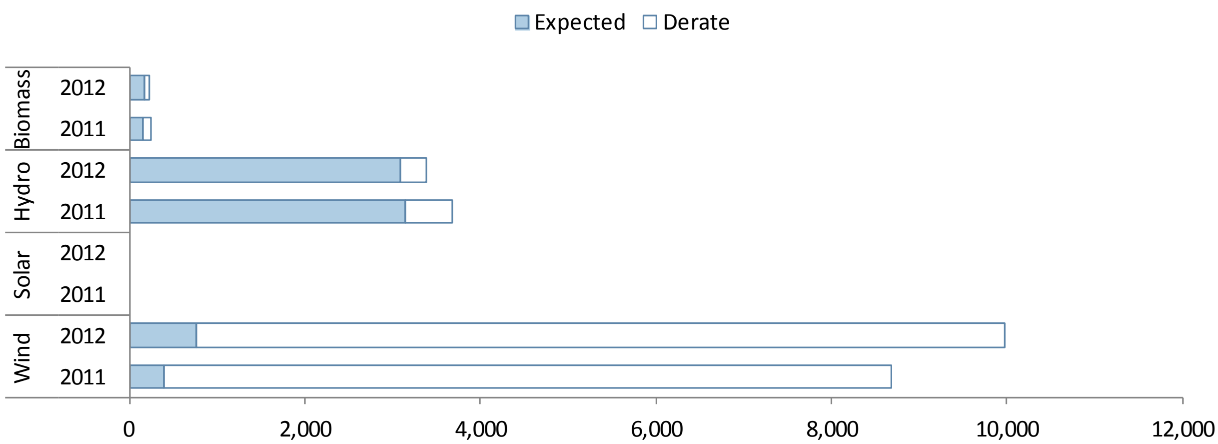


Table 17: MISO Renewable Generation

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	382	765	0	0	3,144	3,088	148	173
Derate	8,290	9,204	0	0	524	302	96	50
Nameplate	**8,672**	**9,969**	**0**	**0**	**3,668**	**3,390**	**244**	**223**

Currently, 10,791 MW of wind resources are registered with MISO; however, MISO applies a 14.7 percent wind capacity credit to MISO wind resources based on their historical performance. The 14.7 percent system wide MISO wind capacity credit is based on determining the Effective Load Carrying Capacity (ELCC) of the intermittent wind resources. For more detailed information regarding the wind capacity credit and ELCC study please see the 2012 LOLE study report. Applying the 14.7 percent capacity credit brings the wind capacity down from 10,791 MW to 1,586 MW; however, MISO is not expecting 1,586 MW on peak. Of the 1,586 MW of wind, only 765 MW are registered as designated network resources in March 2012 commercial model, and are expected to serve MISO load during the 2012 summer season. Therefore, of the 10,791 MW of registered wind resources, MISO anticipates 765 MW of wind capacity on peak during the 2012 summer.

Capacity Transactions

Sellers of generation external to MISO submit generation obligations (MW) through the Module E process for each planning month. Currently, 3,081 MW of Firm imports are obligated for the peak month of 2012 summer. Currently, under the MISO Module E construct, obligations do not go beyond the planning month.

Table 18 includes the capacity transaction values for 2012 Summer Peak. Historically, these values have been determined by the Eastern Interconnection Reliability Assessment Group (ERAG). Import values into the MRO have been provided as in the past. In future assessments, these values should be reported on a sub-regional basis. In the below values, the MRO base case flow is 3,201 MW of net imports (Expected and Firm).

Table 18: MISO Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	3,081	1,426	1,655
Expected	1,933	387	1,546
Total	**5,014**	**1,813**	**3,201**

Transmission

Several transmission projects are expected to be completed by the end of the summer season to enable reliable and efficient transmission service for the MISO region. These include 112 miles of new lines, line upgrades and re-builds. Among these projects are four 230 kV lines in Duke Energy Midwest (DEM), Montana Dakota Utilities (MDU), American Transmission Corporation (ATC) and Ottertail Power (OTP), respectively, and one 345 kV line in ATC. Also, expected to be in service are one new bulk power transformer and two transformer upgrades in areas of MDU, Ameren Illinois and ATC. MISO does not anticipate any existing, significant transmission lines or transformers being out of service through the summer season. MISO does not have any transmission constraints that could significantly impact reliability. Interregional transmission transfers are not available at this time.

Operations

MISO has not performed any special operating studies to determine the impacts of adverse conditions for the 2012 summer season; however, MISO is evaluating the impact of potential low water level issues across the MISO footprint due to a drier than average 2011-2012 winter season and other scenarios that would detract from projected reserve levels. This analysis is documented in the Vulnerability Assessment section of this report. Additionally, MISO is conducting a Summer Readiness Workshop, consistent with prior years, where stakeholder collaboration helps maximize preparedness for the summer season. This workshop includes an assessment of our resources and the expected Planning Reserve Margin, given a forecasted peak load, an assessment of the transmission system under stressed conditions, and a review of key Emergency Operating Procedures (EOP) to ensure familiarity with steps and expectations.

While MISO has not implemented any new EOPs associated with variable resources over the last year, the registration of Dispatchable Intermittent Resource (DIR) continues to increase the availability of dispatchable wind in the MISO BA. As of March 1, 2012, nearly 40 percent of MISO wind resources have registered and operate as a DIR. Another 40 percent will be required to register and operate as a DIR by March 1, 2013.

MISO does not anticipate any reliability concerns as a result of minimum demand and over generation during the 2012 summer period. MISO has a Supply Surplus procedure that contains steps for managing such conditions to mitigate potential impacts on reliability. In addition, the launch of DIR on June 1st, 2011 has resulted in more timely elimination of minimum generation conditions as these resources can now be dispatched down and may set a very low Locational Marginal Price (LMP), incenting other generation to offer more flexibility to be reduced as well. MISO also reviews forecasted system conditions a few days in advance of any expected minimum generation conditions and communicates the impending situation to MISO stakeholders to allow participants a chance to schedule generation maintenance during these times.

During times of peak conditions or when MISO otherwise forecasts the potential for maximum generation conditions, we survey Local Balancing Authorities to obtain the amount of their demand response resources that would be available under a given notification time (2 hours for example). If we reach the point of needing to call on these resources, we deploy only the amount needed, and expect that all will perform. The use of these resources is part of the progression through our Capacity Emergency procedure. If some demand response resources do not perform there are other resources available to us in the subsequent steps of the procedure that we would consider engaging if necessary.

The number of times that a demand response resource could be deployed during any period would be restricted by the type of resource and its offer parameters. For a DRR Type II, the combination of its Minimum Run Time and Minimum Down Time once deployed would restrict the resource's availability for deployment during the remainder of the period. Similarly, for a DRR Type I, the combination of its Minimum Interruption, Minimum Duration and Minimum Non-Interruption Interval would do the same.

MISO could see an impact to its generation fleet from the abnormally dry conditions that persist in some areas within our Footprint. According to the National Oceanic and Atmospheric Administration (NOAA), the 2011-2012 winter season was drier than average across the entire United States. This limited snowfall for many locations. Snow cover had the 3rd smallest footprint in the 46 years it has been measured. This contributed to areas of moderate to severe drought in the Upper Midwest and Northern Plains, which could impact the availability of water, used to cool generating facilities in these areas. MISO is currently collaborating with stakeholders to assess the potential magnitude of this issue.

MISO does not foresee significant impacts to reliability during the 2012 summer season that would result from regulatory restrictions. However, MISO does anticipate that the recently finalized and/or developing EPA regulations will impact MISO in the future. Specifically, the recent delay of the implementation of the Cross-State Air Pollution Rule (CSAPR) has delayed impacts beyond the 2012 summer season. MISO continues to work, both internally and in collaboration with stakeholders, to maximize preparedness efforts for the impacts of CSAPR and other potential regulations. This includes conducting ongoing studies to determine the amount of generation maintenance that could be scheduled in a given season, assuming a reduced capacity level directly due to regulation.

NERC's Recommendation to Industry: Considerations of Actual Field Conditions in Determination of Facility Ratings[73] is currently in its implementation phase. While the assessment results may lead to derates of transmission lines or outages during the coming season, coordination between the Transmission Owners, Transmission Operators, and Reliability Coordinators have helped alleviate reliability concerns. Advanced notice of impending derates allows for coordination efforts to take place, such that even a sudden derate or outage is treated like a forced outage and reliability procedures and processes address the situation. MISO does not anticipate any other unusual operating conditions for the 2012 summer season.

Vulnerability Assessment

MISO may experience low water level issues, similar to what was experienced during the 2006 summer season, across the MISO footprint due to a drier than average 2011-2012 winter season. MISO compared the EFORd from 2006 to MISO's 5 year average EFORd, and it was determined that the 5 year average rate captures the impact of low water issues. Therefore, MISO does not anticipate the forecasted reserve levels to deteriorate due to drought conditions during the 2012 summer months.

MISO does not have reliability concerns for the upcoming summer due to long-term generator outages, unresponsive demand response, or increases in variable generation. MISO has not identified any Special Protection Systems (SPS) or Remedial Action Schemes (RAS) that have been installed since last summer.

MISO does not expect environmental regulations to have an impact during the upcoming summer season; however, MISO is currently studying potential resource adequacy impacts due to pending environmental regulations that could come into impact subsequent seasons. Specifically, MISO is continuing to evaluate four proposed EPA regulations: Cooling Water Intake Structures (CWIS), Coal Combustion Residuals (CCR), Cross State Air Pollution Rule (CSAPR), and Mercury and Air Toxics Standards (MATS). The CSAPR ruling has been stayed by the courts; however, MISO is evaluating the impact of this rule for planning year 2013 and beyond. One potential impact of CSAPR is increased maintenance outages during off-peak months. MISO is currently conducting studies to determine the amount of allowable maintenance which may be taken out in a given month while still maintaining annual system reliability at or better than a Loss of Load Expectation (LOLE) of 1 day in 10 years.

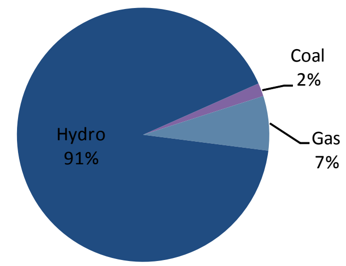
At this time MISO does not know of any generators that will be out of service during the 2012 summer season for installation of environmental controls. It is the responsibility of MISO's Market Participants to ensure fuel supplies are adequate. At this time, MISO membership has not voiced concern about inadequate fuel supply for the upcoming summer season.

[73] http://www.nerc.com/filez/facility_ratings_alert.html.

MRO-Manitoba Hydro

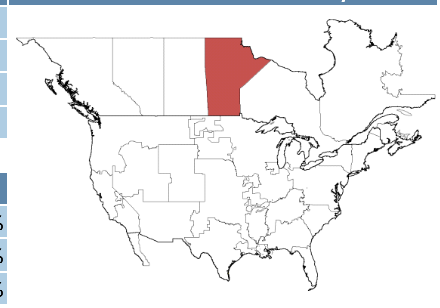
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	5,353	-
Future-Planned	11	-
Supply-Side Demand Response	227	-
Net Capacity Transactions	-1110	-
Anticipated	**4,481**	**43.68%**
Existing-Other and Future-Other	0	-
Prospective	**4,481**	**47.66%**
Reference Margin Level	-	**12.00%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**3,166**	**3,143**
Demand-Side Demand Response (2012)	-	0
Supply-Side Demand Response (2011)	0	-
Total Internal	**3,166**	**3,143**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	3,166	-0.73%
Actual Peak Demand	3,378	-6.96%
All-Time Summer Peak Demand (July 25, 2007)	3,422	-8.15%

Note: Additional information regarding the methods and assumptions used in the development of the MRO-Manitoba Hydro seasonal assessment can be found in Appendix I and on the NERC website.[74]

Assessment Area Highlights

The Reserve Margins for the Manitoba Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level throughout the 2012 summer season.

A total of 220 MW of capacity additions will be added during the 2012 summer. According to the Manitoba demand forecast, Total Internal Demand has decreased from 3,166 MW to 3,143 MW since the 2011 summer. This equates to an annual growth rate of -.73 percent.

Planning Reserve Margins

Manitoba is projecting adequate Planning Reserve Margins during the 2012 summer, with all three categories expected to exceed 27.0 percent throughout. As a Region with predominately hydro resources, Manitoba has both an energy criterion and a capacity reserve margin criterion. The capacity reserve margin criterion, which is considered as the NERC-termed Reference Margin Level, requires a minimum of 12 percent reserve, above the forecasted peak demand. This criterion is more stringent, compared to the 10 percent level assigned to predominately hydro systems that do not submit a Reference Margin Level. Table 19 includes the 2011 and 2012 reserve margins for the MRO-Manitoba Assessment Area.

[74] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

Table 19: MRO-Manitoba Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	12.00%	12.00%
Existing-Certain & Net Firm Transactions	41.19%	36.68%
Anticipated	41.54%	43.68%
Prospective	41.54%	47.66%

Manitoba Hydro has planned and maintained its system in accordance with good utility practice, such that adequate Planning Reserve Margins shall be maintained throughout the summer season. No unit retirements, extraordinary load growth or additional environmental restrictions are expected to impact reliability. Manitoba Hydro does not anticipate any significant challenges to maintaining assessment projections throughout the 2012 summer season.

Demand

As seen in Table 20, the actual peak demand in summer 2011 was 3,378 MW. The peak demand for summer 2011 was forecast to be 3,166 MW. Last summer was warmer than normal and the peak demands occurred at higher temperatures than in previous years.

Table 20: MRO-Manitoba Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	3,166	3,143	-23	-0.73%
Total Internal	3,166	3,143	-23	-0.73%

The 2011 summer peak forecast for Total Internal Demand was 3,166 MW. The 2012 forecast is 3,143 MW. This amounts to a 1 percent decrease that can be attributed to the enhancement of the hourly load model, which contributed to a small decrease in monthly summer peaks.

Demand-Side Management

Demand response used for ancillary services (non-spinning reserves) is 50 MW for all months during the summer season. These reserves satisfy a portion of the MISO-Manitoba Hydro Contingency Reserve Sharing Group reserve requirements and are only deployed to help recover from large generation related contingencies on the system.

Manitoba Hydro’s Curtailable Rate Program (CRP) is not intended to reduce the peak demand, but rather to meet reliability obligations. Manitoba Hydro will curtail customers in response to system emergencies and to maintain planning and operating reserves. Figure 27 and Table 21 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the MRO-Manitoba Assessment Area.

Figure 27: MRO-Manitoba Demand Response

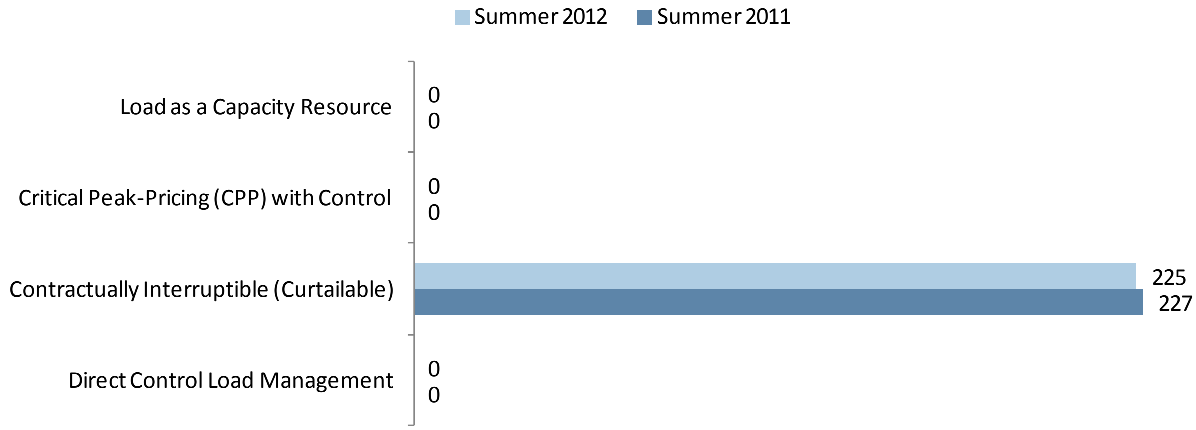


Table 21: MRO-Manitoba Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	0	0	0
Contractually Interruptible (Curtailable)	227	0	225
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	0	0	0
Total Demand Response	**227**	**0**	**225**
Percentage of Total Internal Demand	**7.17%**	**0.00%**	**7.16%**

In Manitoba, new conservation (Energy Efficiency) ranges between 28 MW and 32 MW throughout the summer. Manitoba Hydro's current Power Smart portfolio includes customer service, cost-recovery, incentive-based and rate-based initiatives and programs customized to meet the specific energy needs of the residential, commercial, and industrial markets. This portfolio, consisting of Energy Efficiency, conservation, load management and customer self-generation programs (behind-the-meter generation), is designed to help customers conserve energy, reduce energy costs and protect the environment. Generally, no specific state or regulatory drivers affect demand-side management in Manitoba.

Generation

For the 2012 summer, 5,151 MW of Existing-Certain, and 125 MW of Existing-Other resources are expected to be available during the peak. There will be no Existing-Inoperable capacity during the 2012 summer. Table 22 includes projections of MRO-Manitoba resources for the 2011 and 2012 summer.

Table 22: MRO-Manitoba Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	5,353	5,151
Future-Planned	11	220
Supply-Side Demand Response	227	225
Net Capacity Transactions	-1,110	-1,080
Anticipated	**4,481**	**4,516**
Existing-Other and Future-Other	0	125
Prospective	**4,481**	**4,641**

Manitoba Hydro's primary energy source is through natural water resources. Unit 6 of the Kelsey Generation Station is currently undergoing upgrades scheduled to be completed by May 26, 2012. These upgrades to the unit are expected to add 11 MW of additional Existing-Certain capacity. Additional units at the Wuskwatim Generating Station will be phased in during the 2012 summer. The latest schedule of in-service dates is as follows:

- Unit 1 – June 1, 2012 (74 MW)
- Unit 3 – July 1, 2012 (74 MW),
- Unit 2 August 1, 2012 (74 MW)

These units will provide a total of 208 MW (including aggregate losses when all units are online). Finally, Expansion of the St. Leon Wind Farm is scheduled to be completed by the end of the 2012 summer season and will add an additional 16.5 MW. Manitoba Hydro resource planning does assume an 8 percent capacity factor for wind in the summer assessment period during on-peak hours.

No unit retirements are planned and no project deferments or delays are expected this summer. Various Scheduled Outages this season will range from 120 MW to 529 MW, with 121 MW projected to be out during the peak. Of these outages, approximately 20 MW from the Pointe du Bois Generating Station are expected to remain out of service throughout the summer season. No significant short-term impacts are anticipated due to this ongoing outage.

Manitoba has two existing wind farms: St. Leon and the St. Joseph. St. Leon currently has 104 MW (8 MW on-peak) of nameplate capacity, expected to increase to 120.5 MW (9 MW on-peak) by the end of the 2012 summer. The St. Joseph wind farm maintains a nameplate capacity of 138 MW (11 MW on-peak). Again, the expected on-peak capacity for the summer season equates to 8 percent of the nameplate capacity. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 28 and Table 23.

Figure 28: MRO-Manitoba Renewable Generation

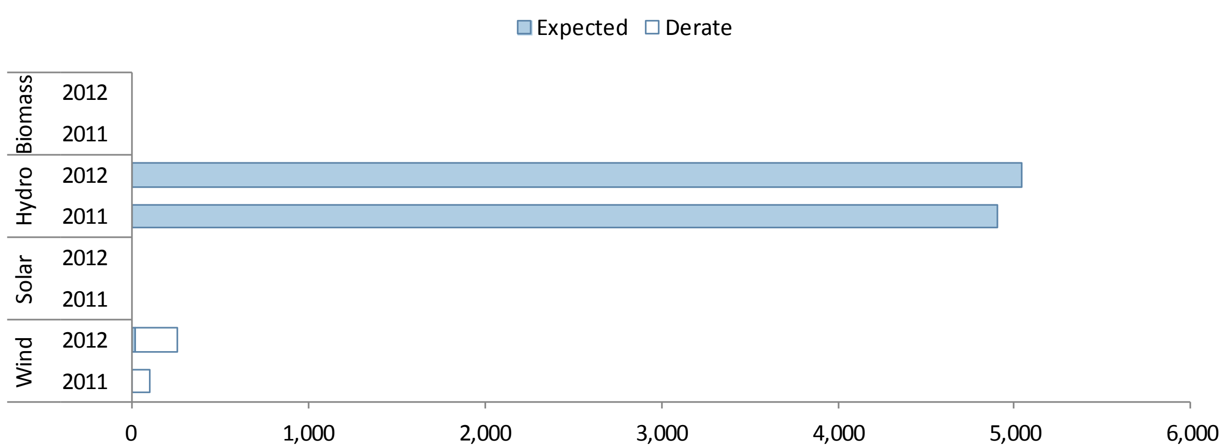


Table 23: MRO-Manitoba Renewable Generation

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	0	20	0	0	4,901	5,042	0	0
Derate	104	236	0	0	0	0	0	0
Nameplate	**104**	**256**	**0**	**0**	**4,901**	**5,042**	**0**	**0**

The expected on-peak capacity ranges for hydro resources are projected to fall between 4,951 MW and 4,984 MW during the summer season. The expected maximum capacity during this period is 5,086 MW.

Capacity Transactions

All of Manitoba Hydro's dependable export capacity is backed by Firm contracts. There are no capacity imports projected for the summer season. These contractual agreements have Firm transmission associated with them. Manitoba Hydro does not project any capacity transactions beyond the contract terms. On-peak capacity transactions projected for the 2012 summer are included in Table 24.

Table 24: MRO-Manitoba Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	0	1,080	-1,080
Expected	0	0	0
Total	**0**	**1,080**	**-1,080**

Manitoba Hydro's emergency energy imports are characterized under the MISO-Manitoba Hydro Contingency Reserve Sharing Group (CRSG) agreement. Only upon significant contingencies of generation or transmission facilities do Manitoba Hydro system operators have the ability to request emergency energy imports from MISO under the CRSG. Manitoba Hydro is its own Balancing Authority so all emergency energy imports would be from external Balancing Authorities in MISO. The total reserve carried in the reserve sharing group is 2,000 MW (150 MW for Manitoba Hydro, 1,850 MW for MISO). Manitoba Hydro is expected to exhaust its own available reserves prior to making an emergency energy request.

Transmission

There are no project delays or temporary service outages that will impact reliability during the 2012 summer season. Additionally, Manitoba Hydro does not foresee any projects that will be needed to maintain or enhance reliability for the 2012 summer season.

Operations

On an annual basis, Manitoba Hydro performs an operational study to determine the storage reserve requirements necessary to meet demand under the lowest historic flow on record and a high load forecast. There have been no unique operational problems observed. Additionally, there are no new operating procedures developed for the 2012 summer season. However, Manitoba Hydro has existing operating procedures for the two wind farms located in Manitoba.

Potential reliability concerns resulting from minimum demand and over generation include localized over voltage concerns in the northern Manitoba AC transmission system as well as hydraulic constraints on Lower Nelson. At minimum demand, forebay management at Lower Nelson River generating stations becomes a concern as a constrained ability to discharge water efficiently develops. Potential impacts include spill and forebay license violations.

To mitigate over voltage concerns, reactors could be switched on, capacitors switched off, transformer tap settings may be adjusted, or transmission lines may be removed from service.

Manitoba Hydro will curtail customers in response to system emergencies and to maintain planning and operating reserves. The industrial customers with CRP agreements are required to maintain the availability of the resources more than 95 percent of the time. No performance concerns are expected.

Various restrictions are placed on the resources based upon the CRP agreement between Manitoba Hydro and the specific industrial customers. Minimum notice to curtail load ranges between 5 minutes, 60 minutes, and 48 hours. Maximum duration per curtailment varies between 4 hours, 4.25 hours, and 10 days. The maximum daily hours of curtailment ranges between 6, 8, 10, and 24 hours. The maximum annual number of curtailments is 3, 15, or 25 times. The maximum annual hours of curtailment varies from 60, 63.75, 106.25, and 720.

There are no environmental or regulatory restrictions that would impact reliability. Finally, Manitoba Hydro does not anticipate any unusual operating conditions that could significantly impact reliability for the upcoming summer season.

Vulnerability Assessment

As a predominately hydro region, Manitoba Hydro has an energy criterion that requires adequate energy resources to supply the Firm energy demand in the event that the lowest recorded coincident river flow conditions on the 96-year hydraulic flow record are repeated. In other words, the Manitoba Hydro system is designed and operated to serve all Firm load requirements under the worst inflow conditions on record coincident with high winter load conditions. Drought contingency plans are well established and operational concerns are not a factor.

Manitoba Hydro's system tends to be energy constrained rather than capacity constrained. As a result of the tendency to be energy constrained, there are typically significant amounts of surplus generation capacity available. Therefore it is possible to manage resources around significant long-term generator outages of capacity resources.

Manitoba Hydro's CRP is only used to meet reliability obligations. If these resources became unavailable, other sources of reserves internal to Manitoba Hydro and external via the MISO-Manitoba Hydro CRSG agreement would be used in emergency situations. With respect to resource adequacy, Manitoba Hydro does not rely on demand response resources when evaluating resource adequacy requirements.

The most likely increase in variable generation in the foreseeable future is wind related. The addition of new resource would help with resource adequacy issues and the addition of plausible amounts of wind generation does not raise any significant operational concerns given the significant operating flexibility of the existing hydro resources.

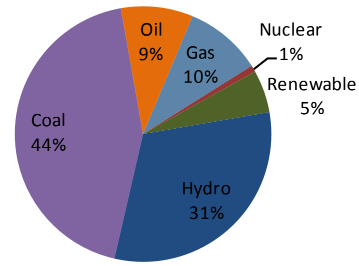
The Raven Lake MR11 Tripping SPS was installed at Raven Lake station in October 2011 with the SPS tripping function disabled. The MRO has approved placing this SPS into service. Manitoba Hydro is deciding on a suitable date to place the SPS in service. The purpose of this SPS is to prevent overloading of the 115 kV line MR11 under certain system contingencies. No system changes or reinforcements are currently planned that will allow this SPS to be retired or replaced.

Manitoba Hydro does not anticipate any supply or transportation issues for the 2012 summer season. Alberta gas supplies and transportation to Manitoba are plentiful. TransCanada Pipeline has been experiencing significant de-contracting of Firm transport by its customers. It has more than enough transport available should Manitoba Hydro have to run its gas-fired generation during the summer season. Gas supply is available either from Alberta or from the East via backhaul arrangements. Manitoba Hydro does not have any Firm arrangements in place for supply or transport at this time.

MRO-MAPP

2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	7,027	-
Future-Planned	294	-
Supply-Side Demand Response	93	-
Net Capacity Transactions	-1331.782	-
Anticipated	**6,082**	**29.01%**
Existing-Other and Future-Other	0	0
Prospective	**6,082**	**29.01%**
Reference Margin Level	-	**15.00%**

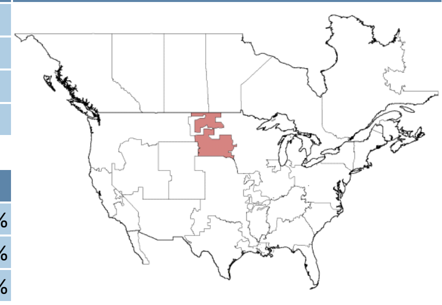
On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**5,027**	**4,715**
Demand-Side Demand Response (2012)	-	84
Supply-Side Demand Response (2011)	60	-
Total Internal	**5,087**	**4,799**

2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	5,027	-6.21%
Actual Peak Demand	4,732	-0.36%
All-Time Summer Peak Demand (August 1, 2007)	6,249	-24.55%

Assessment Area Boundary



Note: Additional information regarding the methods and assumptions used in the development of the MRO-MAPP seasonal assessment can be found in Appendix I and on the NERC website.[75]

Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the MAPP Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The Reserve Margins for the MAPP Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

A total of 294 MW of capacity additions will be added through the summer of 2012. According to the MAPP demand forecast, Total Internal Demand has decreased from 4,997 MW to 4,799 MW since the 2011 summer. This equates to an annual growth rate of -4.0 percent.

Planning Reserve Margins

MAPP is projecting adequate Planning Reserve Margins during the 2012 summer season. All reserve margin categories (Existing-Certain, Anticipated, Prospective) exceed the target reference margin of 15 percent. MAPP does not anticipate any scenarios that would lead to a significant detraction from these projections for the upcoming summer season. Table 25 includes the 2011 and 2012 reserve margins for the MRO-MAPP Assessment Area.

[75] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

Table 25: MRO-MAPP Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	15.00%	15.00%
Existing-Certain & Net Firm Transactions	22.92%	22.77%
Anticipated	24.61%	29.01%
Prospective	24.61%	29.01%

Demand

MAPP assumes normal (50/50) weather and normal economic assumptions. The 2011 MAPP actual summer peak non-coincident demand was 4,732 MW. Last summer's demand forecast was 5,087 MW, based on MRO-submitted data. This summer's peak demand forecast is 4,799 MW. Non-coincident, internal peak demands were used to aggregate individual LSE loads for use in the MAPP forecast. Resource evaluations are based on non-coincident peak demand conditions. Table 26 includes the demand forecast for the 2011 and 2012 summer for the MRO-MAPP Assessment Area.

Table 26: MRO-MAPP Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	5,027	4,715	-312	-6.21%
Total Internal	5,087	4,799	-288	-5.67%

Demand-Side Management

The total amount of Demand Response that is expected to be available on-peak for the 2012 summer season is 177 MW. An additional 225 MW of Energy Efficiency is also projected to be available during the peak. Interruptible Demand and Demand-Side Management (DSM) programs amount to 8.4 percent of the MAPP Projected Total Internal Peak Demand of 4,799 MW. The month of July was used as the peak summer month in this assessment.

A wide variety of programs, including direct load control (such as electric appliance cycling) and interruptible load, may be used to reduce peak demand during the summer season. MAPP LSEs use various measurement and verification programs for demand response, such as those based upon International Performance Measurement and Verification Protocols (IPMVP). Energy Efficiency is verified through several means, such as use of the Minnesota Deemed Savings Database, provided by the Minnesota Office of Energy Security. Figure 29 and Table 27 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the MRO-MAPP Assessment Area.

Figure 29: MRO-MAPP Demand Response

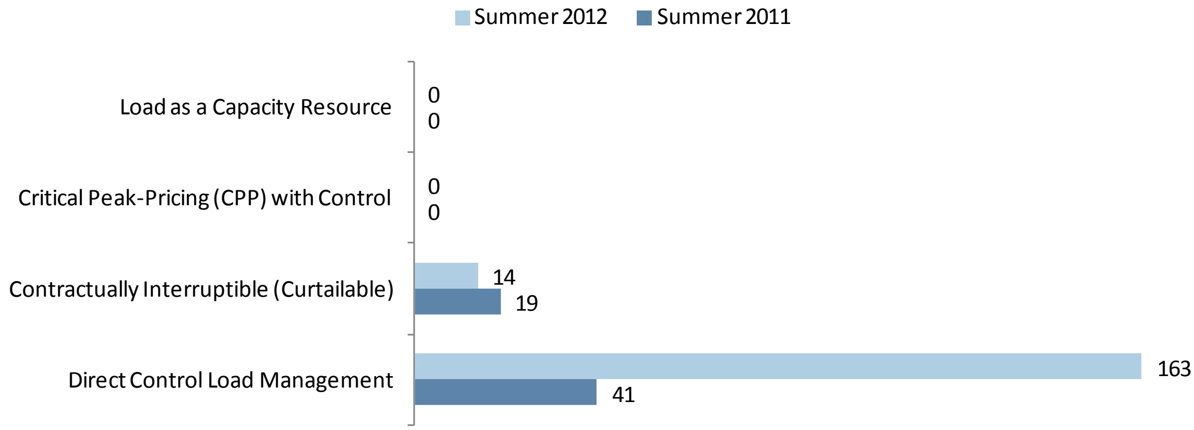


Table 27: MRO-MAPP Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	41	84	79
Contractually Interruptible (Curtailable)	19	0	14
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	0	0	0
Total Demand Response	**60**	**84**	**93**
Percentage of Total Internal Demand	**1.18%**	**1.75%**	**1.94%**

There have not been any significant changes regarding dispatchable and controllable demand response, or demand response used for ancillary services, in MAPP. The amount of Demand-Side Management in these areas remains unchanged.

Generation

The Existing-Certain capacity projections for the 2012 summer season are 7,027 MW. MAPP does not currently have Existing-Other or Existing-Inoperable capacity resources. The primary fuel sources in MAPP are coal (47 percent), hydro (29 percent), oil (11 percent), natural gas (9 percent), and wind (4 percent). There have been no Existing-Certain capacity additions since last season. Table 28 includes projections of MRO-MAPP resources for the 2011 and 2012 summer.

Table 28: MRO-MAPP Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	6,823	7,027
Future-Planned	80	294
Supply-Side Demand Response	60	93
Net Capacity Transactions	-926	-1,332
Anticipated	**6,037**	**6,082**
Existing-Other and Future-Other	0	0
Prospective	**6,037**	**6,082**

There are 294 MW of Future-Planned capacity resources projected to be added either during or before the 2012 summer. There have been no unit retirements, deferments, or derates since the previous season.

Of the existing capacity resources, 303 MW of on-peak wind generation is expected from the total 1,155 MW of nameplate wind capacity. This dataset uses 10 years or the life of the wind farm.

Additionally, there are 3 MW of existing biomass capacity and 2,127 MW of hydro. No adverse hydro conditions are projected for the 2012 summer, with reservoirs returning to normal levels, after several seasons of below-normal conditions. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 30 and Table 29.

Figure 30: MRO-MAPP Renewable Generation

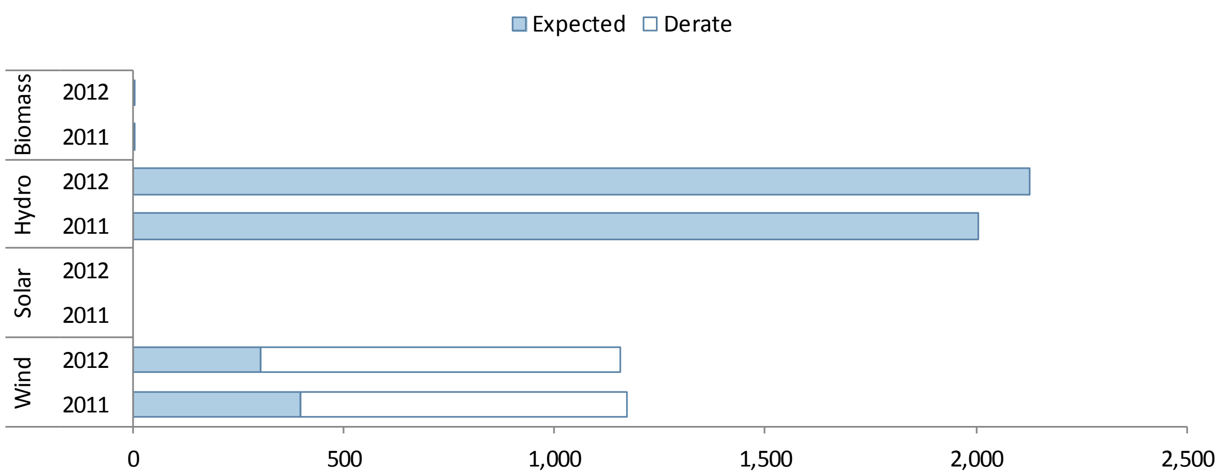


Table 29: MRO-MAPP Renewable Generation

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	398	303	0	0	2,007	2,127	3	3
Derate	776	855	0	0	0	0	0	0
Nameplate	**1,173**	**1,158**	**0**	**0**	**2,007**	**2,127**	**3**	**3**

MAPP is not expecting conditions that would reduce capacity for the 2012 summer season. MAPP does not anticipate any significant generating units to be out of service or retired during the 2012 summer season.

Capacity Transactions

For the 2012 summer season, MAPP is projecting total Firm imports of 235 MW. Additionally, MAPP projects total Firm exports to amount to 1,567 MW. On-peak capacity transactions projected for the 2012 summer are included in Table 30.

Table 30: MRO-MAPP Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	235	1,567	-1,332
Expected	0	0	0
Total	**235**	**1,567**	**-1,332**

Transmission

The rebuilding of the 115 kV line from Charlie Creek – Watford City - Williston to 230 kV is expected to be in operation by the end of June 2012. Temporary operating guides will be developed as necessary to reliably manage this outage. Additionally, Northwestern Energy recently energized the Letcher Jct. – Mitchell 115KV line. This line was placed in service in December 2011. The project provides additional support and reliability to the Mitchell area.

MAPP is not aware of any transmission constraints or transmission issues that will affect system reliability (*i.e.*, deliverability of generation to network load).

Operations

No significant operational issues are expected this summer for the MAPP Planning Authority area. The existing operating guides and temporary operating guides that are developed as needed, have maintained reliable system conditions throughout the year and will continue to be used this summer.

The MRO-MAPP Assessment Area does not anticipate any reliability concerns from minimum demand or over generation situations. MAPP does not anticipate any environmental or regulatory restrictions that would impact reliability this summer. Normal load levels are anticipated for the 2012 summer season and there are no concerns with resource adequacy or demand response in meeting projected peak demands.

Vulnerability Assessment

MAPP plans to rely on current generation capacity margins and stable water levels this season. Overall, there are no resource adequacy or operational concerns for the following conditions: long-term (extended) drought; significant long-term generator outages; unresponsive or unavailable demand response; significant increases in variable generation. MAPP is unaware of any reliability impacts that would result specifically from environmental regulations.

MAPP does perform studies that consider known and anticipated fuel supply or delivery issues. Because the MAPP Planning Authority area has a diverse fuel supply, inventory management, and delivery methods, there is currently no specific mitigation procedure in place, should fuel delivery problems occur. Resource providers do not foresee any significant fuel supply and/or fuel delivery issues for the upcoming summer. Any fuel supply issues that may develop will be handled on a case-by-case basis.

Various MAPP reliability studies are performed in accordance with the MAPP Members Reliability Criteria and Study Procedures Manual.[76] Transient, voltage, and small signal stability studies[77] are performed as part of the near-term/long-term transmission assessments.[78] Reactive power resources are considered in on-going operational planning studies. No transient, voltage, or small signal stability issues are expected that impact reliability during the 2012 summer season.

All MAPP LSEs have established a Reference Margin Level through application of the MAPP Loss of Load Expectation (LOLE) Study. This study was last performed and completed by MAPP on December 31, 2009.[79] Similar to NERC's guidelines, the MAPP LOLE study recommends a 15 percent Reference Margin

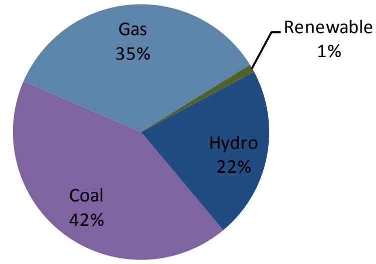
[76] MAPP Members Reliability Criteria and Study Procedures Manual, November, 2009.
[77] MAPP Small Signal Stability Analysis Project Report, November 2010.
[78] 2011 MAPP System Performance Assessment.
[79] MAPP Loss of Load Expectation Study 2010-2019, December 2009.

Level for predominantly thermal systems, and 10 Reference Margin Level for predominantly hydro systems.

MRO-SaskPower

2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	3,544	-
Future-Planned	0	-
Supply-Side Demand Response	91	-
Net Capacity Transactions	-50	-
Anticipated	**3,585**	**23.50%**
Existing-Other and Future-Other	0	-
Prospective	**3,585**	**31.68%**
Reference Margin Level	-	**13.00%**

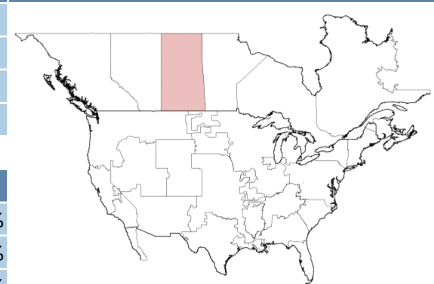
On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**2,954**	**2,953**
Demand-Side Demand Response (2012)	-	91
Supply-Side Demand Response (2011)	91	-
Total Internal	**3,045**	**3,044**

2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	2,954	-0.05%
Actual Peak Demand	2,988	-1.18%
All-Time Summer Peak Demand (July 18, 2011)	2,988	-1.18%

Assessment Area Boundary



Note: Additional information regarding the methods and assumptions used in the development of the MRO-SaskPower seasonal assessment can be found in Appendix I and on the NERC website.[80]

Assessment Area Highlights

This assessment presents summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the province of Saskatchewan. Projections are based on internal SaskPower data, economic indicators, long-term weather forecasts, and historic load data.

The reserve margins for the Saskatchewan Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

No capacity additions will be added during the 2012 summer. According to the SaskPower demand forecast, Total Internal Demand has increases from 3,045 MW to 3,134 MW since last summer. This equates to an annual growth rate of 1.03 percent.

Planning Reserve Margins

An adequate Planning Reserve Margin is projected for Saskatchewan during the 2012 summer season. The SaskPower Reference Margin Level for Saskatchewan is 13 percent, while all reserve margin categories exceed 17 percent throughout the summer. The peak month considered for this assessment is July, at which point the Anticipated Reserve Margin is 23.5 percent. However, the Anticipated Reserve Margin does drop to 17 percent in September. Adequate resources have been planned for Saskatchewan to meet anticipated load for the 2012 summer period. Additionally, there are no anticipated challenges that would lead to significant reductions of the reserve margin projections for

[80] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

Saskatchewan during the 2012 summer. Table 31 includes the 2011 and 2012 reserve margins for the MRO-SaskPower Assessment Area.

Table 31: MRO-SaskPower Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	15.00%	13.00%
Existing-Certain & Net Firm Transactions	17.73%	23.50%
Anticipated	17.73%	23.50%
Prospective	17.73%	31.68%

Demand

For Saskatchewan, the peak Total Internal Demand forecast for 2011 summer assessment period was 3,045 MW, while the actual peak demand for the 2011 summer assessment period was 2,988 MW. The peak demand forecast for all four months of the 2012 summer period is 3,043 MW. This higher demand forecast is due to industrial load and residential load growth. In general, load growth in Saskatchewan, is due primarily to economic growth in the industrial sector. Table 32 includes the demand forecasts for the 2011 and 2012 summers.

Table 32: MRO-SaskPower Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	2,954	2,953	-1	-0.05%
Total Internal	3,045	3,044	-1	-0.05%

Demand-Side Management

The total amount of Demand Response and Energy Efficiency (New Conservation) that is expected to be available on peak for Saskatchewan for the 2012 summer season is 134 MW. Demand Response and Energy Efficiency (New Conservation) resources in Saskatchewan are considered capacity resources used for peak shaving. Figure 31 and Table 33 present the Demand Response forecasted for the 2011 and 2012 summer peaks.

Figure 31: MRO-SaskPower Demand Response

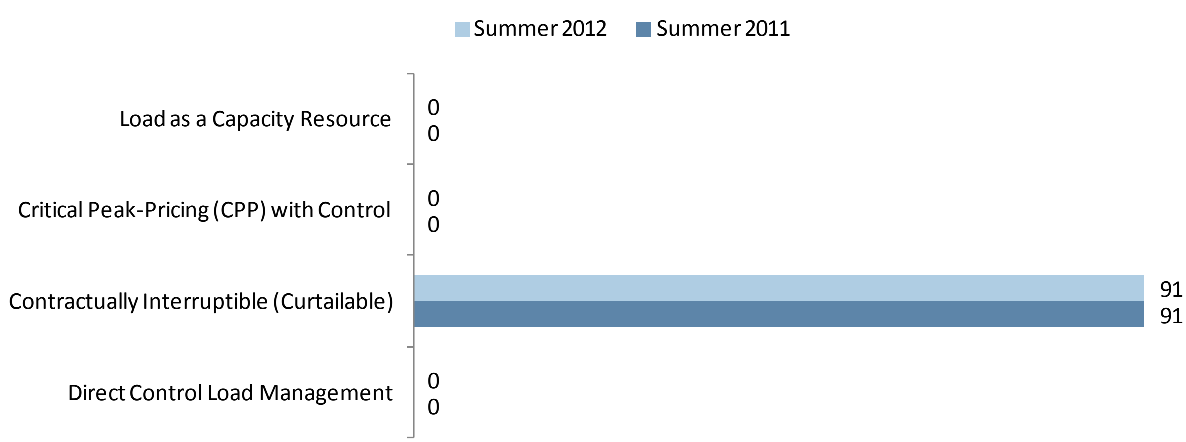


Table 33: MRO-SaskPower Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	0	0	0
Contractually Interruptible (Curtailable)	91	91	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	0	0	0
Total Demand Response	**91**	**91**	**0**
Percentage of Total Internal Demand	**2.99%**	**2.99%**	**0.00%**

The primary driver for Demand-Side Management programs in Saskatchewan is economic incentive.[81] Increases in Demand-Side Management (DSM) for the 2012 summer assessment period will come from growth of existing programs.

Generation

In Saskatchewan, 3,647 MW of Existing-Certain capacity is expected to be available during the peak month. Approximately 237 MW of wind derates, hydro derates, and scheduled outages for maintenance are expected on peak. No resources are expected to be inoperable for this summer. Table 34 includes resource forecasts for the 2011 and 2012 summer.

Table 34: MRO-SaskPower Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	3,544	3,647
Future-Planned	0	0
Supply-Side Demand Response	91	0
Net Capacity Transactions	-50	0
Anticipated	**3,585**	**3,647**
Existing-Other and Future-Other	0	0
Prospective	**3,585**	**3,647**

The primary sources of fuel for Saskatchewan are coal, hydro, and natural gas. Since the 2011 summer assessment period, 89 MW of natural gas generation has been added. However, there is no Future-Planned capacity projected to be added leading up to, or during the 2012 summer season. Additionally, there are no anticipated unit retirements, project deferments, or any other impacts that would affect the existing capacity level since the 2011 summer assessment period. Unit derates similar to the prior season are expected. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 32 and Table 35.

[81] The difference in cost between providing the DSM program and the cost of serving the load.

Figure 32: MRO-SaskPower Renewable Generation

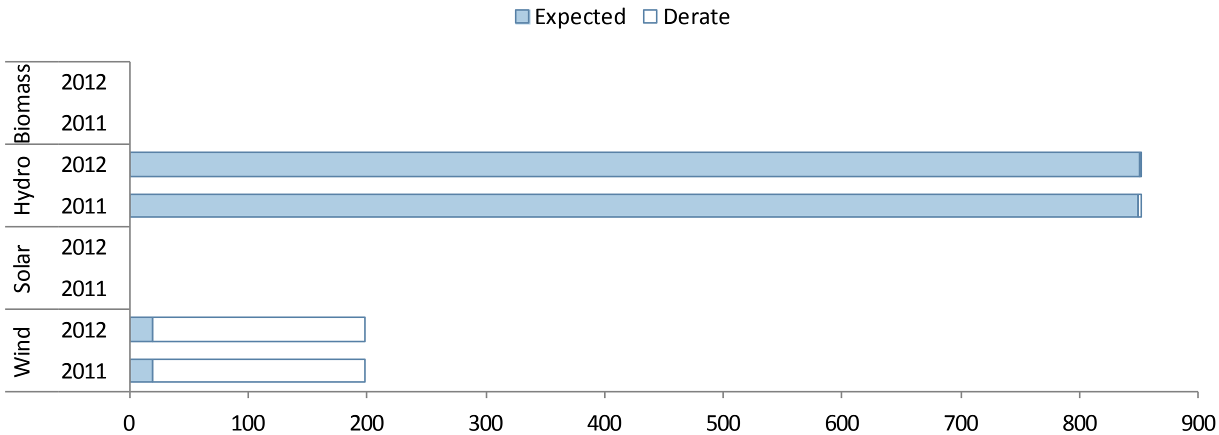


Table 35: MRO-SaskPower Renewable Generation

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	20	20	0	0	850	851	0	0
Derate	178	178	0	0	2	2	0	0
Nameplate	**198**	**198**	**0**	**0**	**852**	**853**	**0**	**0**

There are no units that will be taken out of service or brought back into service during the 2012 summer season in Saskatchewan, other than those that are part of the regular maintenance plan. For Saskatchewan, an average of 20 MW of wind and an average of 850 MW of hydro is expected on-peak during the 2012 summer season. For the 2012 summer season, Saskatchewan plans for 10 percent of wind nameplate capacity to be available to meet on-peak demand. On-peak expected values for hydro assume nameplate net generation less expected seasonal derates due to water conditions.

Capacity Transactions

There are no Firm imports and/or exports backed by contracts, projected during the 2012 summer season.

Transmission

There are no project delays or temporary transmission service outages in Saskatchewan that are expected to impact reliability during the 2012 summer season. Additionally, there are no specific projects that have been identified to maintain or enhance reliability during the 2012 summer season.

Operations

No special operating study requirements for Saskatchewan have been identified for the 2012 summer season. There have been no new operating procedures developed as a result of integration of variable resources. No potential reliability concerns resulting from minimum demand or over generation have been identified.

There are no concerns with the use of demand response resources to meet peak demand for the 2012 summer season for Saskatchewan. Operational procedures for the 2012 summer season will not be impacted as a result of integrating variable resources for Saskatchewan. No environmental and/or regulatory restrictions are anticipated to impact reliability for the 2012 summer season for Saskatchewan.

Vulnerability Assessment

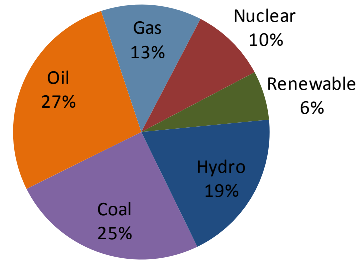
With regards to coordination with the fuel supply industry, coal resources have Firm contracts, are mine-to-mouth, and stockpiles are maintained at each facility in the event that mine operations are unable to meet the required demand of the generating facility. Typically there are 20 days of on-site stockpile for each of the coal facilities which in total represent approximately 47 percent of total provincial installed capacity. Strip coal reserves are also available and only need to be loaded and hauled from the mine. These reserves range from 30 to 65 days depending on the plant.

Natural gas resources have Firm on-peak transportation contracts with large natural gas storage facilities located within the province to back the contracts.

NPCC-Maritimes

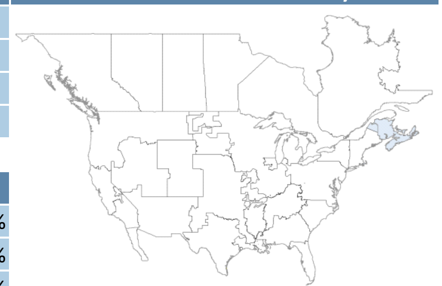
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	4,599	-
Future-Planned	0	-
Supply-Side Demand Response	222	-
Net Capacity Transactions	0	-
Anticipated	**4,821**	**42.13%**
Existing-Other and Future-Other	0	-
Prospective	**4,821**	**42.13%**
Reference Margin Level	-	**15.00%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**3,553**	**3,392**
Demand-Side Demand Response (2012)	-	0
Supply-Side Demand Response (2011)	0	-
Total Internal	**3,553**	**3,392**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	3,553	-4.5%
Actual Peak Demand	3,329	1.9%
All-Time Summer Peak Demand (July 31, 2007)	3,576	-5.1%

Note: Additional information regarding the methods and assumptions used in the development of the NPCC-Maritimes seasonal assessment can be found in Appendix I and on the NERC website.[82]

Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the Maritimes Assessment Area which consists of four sub-regions. Data was collected from individual sub-region and aggregated using a bottom-up approach with projections based on long-term weather forecasts, and historic load data. It should be noted that the Maritimes Area is a winter-peaking system and, as such, does not expect to experience any reliability issues.

The reserve margins for the Maritimes Assessment Area are based in accordance with NPCC Directory #1 Appendix F Procedure for Operational Planning Coordination. As such, the assessment considers the regional operating reserve criteria; 100 percent of the largest single contingency and 50 percent of the second largest contingency. Whereas, the Maritimes Area is a winter-peaking system and there are more than sufficient reserve margins anticipated over this assessment period.

A total of 31.05 MW of capacity additions will be added during the 2012 summer. According to the Maritimes Area demand forecast, Total Internal Demand has decreased from 3,553 MW to 3,392 MW since the 2011 summer. This equates to a decrease rate of 4.5 percent. This decrease can be primarily attributed to the loss of industrial load.

Planning Reserve Margins

When allowances for unplanned outages (based on a discreet MW value representing an historical assessment of the total forced outages in MW typically realized at the time of peak for the given

[82] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

operating season) are considered, the Maritimes Area is projecting more than adequate surplus capacity margins above its operating reserve requirements for the 2012 Summer assessment period.

The projected reserve margin for 2012 Summer period range from 42 percent to 52 percent as compared to the projected capacity margin for the 2011 Summer of 59 percent. Table 36 includes the 2011 and 2012 reserve margins for the NPCC-Maritimes Assessment Area.

Table 36: NPCC-Maritimes Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	15.00%	15.00%
Existing-Certain & Net Firm Transactions	58.91%	42.13%
Anticipated	58.91%	42.13%
Prospective	58.91%	42.13%

The Maritimes Area is a winter-peaking system and has a very diverse fuel supply made up of nuclear (scheduled back in service October 2012), natural gas, coal, oil (both light and residual), pet-coke, hydro, tidal, municipal waste, wind and wood. As such does not expect to experience any reliability issues.

Demand

The Maritimes Area forecasted a peak demand of 3,553 MW to occur during the 2011 summer period, June through September and it was expected to occur during the week of September 25, 2011. The actual peak for 2011 summer was 3,329 on July 21, 2011, which was 224 MW (6.3 percent) lower than the forecasted peak demand. The primary driver in the difference of peaking in July and not September as forecasted was the shutdown of a large industrial load at the beginning of September. The summer 2012 summer peak forecast is 3,392 MW. The 161 MW reduction is due to the loss of industrial load. See Table 37 for 2011 and 2012 summer demand values.

Table 37: NPCC-Maritimes Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	3,553	3,392	-161	-4.53%
Total Internal	3,553	3,392	-161	-4.53%

Demand-Side Management

In the Maritimes Area there is between 207 MW and 275 MW of interruptible demand available during the assessment period; there is 222 MW forecasted to be available at the time of the Maritimes Area seasonal peak. This is approximately 7 percent of the Total Internal Demand. The interruptible load demand that is used is from industrial loads that are metered and therefore can be monitored to determine what level of load would be available to curtail under emergency operating conditions. Figure 33 and Table 38 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the NPCC-Maritimes Assessment Area.

Figure 33: NPCC-Maritimes Demand Response

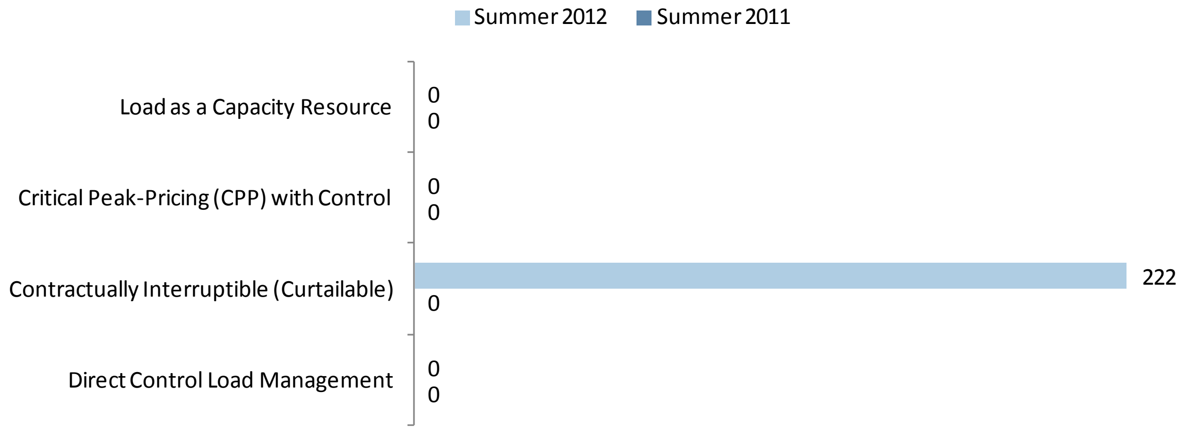


Table 38: NPCC-Maritimes Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	0	0	0
Contractually Interruptible (Curtailable)	0	0	222
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	0	0	0
Total Demand Response	**0**	**0**	**222**
Percentage of Total Internal Demand	**0.00%**	**0.00%**	**6.54%**

The Maritimes Area is broken up into sub-areas and each sub-area has its own energy efficiency programs. These programs are primarily aimed at the residential consumer to help reduce their heating costs. It is usually geared towards heat, as the Maritimes Area is a winter-peaking system.[83]

Generation

The Maritimes Area resources will be 7,457 MW of existing capacity. The Maritimes Area only considers Existing-Certain resources when doing its seasonal assessment. As indicated above the Maritimes Area has a very diverse fuel supply with primary sources of fuel being hydro, oil, coal, natural gas and nuclear.

Existing-Certain resources that have been added since summer 2011 include 49 MW of natural gas and 41.36 MW of wind generation. There are 31.05 MW of planned wind generation expected to be added during the summer 2012 reporting period. Since the last summer assessment a coal fired plant of 299 MW is scheduled to be retired on May 31, 2012. Table 39 includes projections of resources in the Maritimes Assessment Area for the 2011 and 2012 summer.

[83] For further information on the energy efficiency programs please review the links: www.maritimeelectric.com; www.nppower.com; www.mainepublicservice.com; www.emec.com; www.nspower.ca/energy_efficiency/programs/.

Table 39: NPCC-Maritimes Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	5,853	4,599
Future-Planned	0	0
Supply-Side Demand Response	0	222
Net Capacity Transactions	-207	0
Anticipated	**5,646**	**4,821**
Existing-Other and Future-Other	0	0
Prospective	**5,646**	**4,821**

Point Lepreau nuclear generator has been off line for refurbishment since April 1, 2008 and it is scheduled back on line October 2012. The expected installed capacity once Point Lepreau has returned to service is to be approximately 700 MW. In addition, a thermal plant (units 96 MW + 203 MW = 299 MW) is scheduled to be retired on May 31, 2012.

Wind capacity within the Maritimes Assessment Area is expected to be 846 MW with 138.57 MW expected on peak. Wind projected capacity is derated to its demonstrated average output for each summer or winter capability period. In New Brunswick, Prince Edward Island and Northern Maine Independent System Administrator (NMISA) the wind facilities that have been in production over an extended period of time a derated monthly average is calculated using metering data from previous years over each seasonal assessment period. Nova Scotia has decided not to include any wind facilities towards their installed capacity (100 percent derated). A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 34 and Table 40.

Figure 34: NPCC-Maritimes Renewable Generation

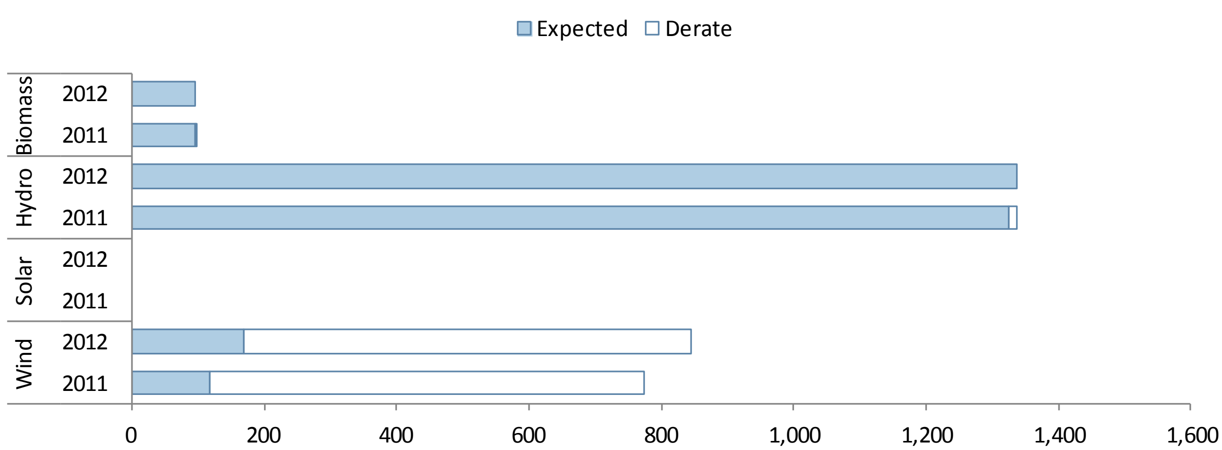


Table 40: NPCC-Maritimes Renewable Resources

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	119	170	0	0	1,325	1,338	96	96
Derate	655	676	0	0	12	0	3	0
Nameplate	**774**	**846**	**0**	**0**	**1,337**	**1,338**	**99**	**96**

For those wind facilities that have not been in service that length of time, the derating of wind capacity in the Maritimes Area is based upon results from the Sept. 21, 2005 NBSO report *Maritimes Wind*

Integration Study.[84] This wind study showed that the effective capacity from wind projects, and their contribution to LOLE, was equal to or better than their seasonal capacity factors. Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects versus a summer peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production. Wind is the only variable resource currently considered in the Maritimes Area resource adequacy assessment. The amount of wind presently operating does not require any special operational changes.

Capacity Transactions

No on-peak capacity transactions have been scheduled at this time. The Maritimes, through existing agreements with neighboring Balancing Authority areas, namely, ISO-NE and TransÉnergie, has established procedures for the acquisition of emergency energy if necessary.

Transmission

No new transmission projects are scheduled to go into service during the 2012 summer period and no outages that would be expected to impact reliability are scheduled.

Operations

Anticipated 2012 summer conditions do not show the need for any special operating studies. The Maritimes Assessment Area assesses its seasonal resource adequacy in accordance with NPCC Directory #1 Appendix F Procedure for Operational Planning Coordination. As such, the assessment considers the regional Operating Reserve criteria; 100-percent of the largest single contingency and 50-percent of the second largest contingency. The amount of wind presently operating does not require any special operational changes.

The Maritimes area does not anticipate any reliability concerns due to minimum demand and over generation. There are adequate generation facilities within the Maritimes that can easily be removed from service to prevent that from happening.

The only demand response considered in resource adequacy assessment for the Maritimes Area is interruptible load. The Maritimes Area uses a 20 percent reserve criterion for planning purposes, equal to 20 percent x (Forecast Peak Load MW – Interruptible Load MW).

There are no environmental or regulatory restrictions which could impact reliability in the Maritimes Area during the assessment period. There are no unusual operating conditions anticipated for the summer that will impact reliability in the Maritimes Area.

Vulnerability Assessment

The Maritimes Area is forecasting normal hydro conditions for the 2012 Summer assessment period. The Maritimes Area hydro resources are run-of-the-river facilities with limited reservoir storage facilities. These facilities are primarily utilized as peaking units or for providing operating reserve.

The Maritimes Area is a winter-peaking system. The summer months are when significant long-term generator outages are planned. Load Management is not included in the resource adequacy assessment for the Maritimes Area. The interruptible load demand that is used is from industrial loads that are

[84] http://www.nbso.ca/Public/_private/2005%20Maritime%20Wind%20Integration%20Study%20_Final_.pdf.

metered and therefore can be monitored to determine what level of load would be available to curtail under emergency operating conditions.

The amount of wind presently operating does not require any special operational changes. If there were a significant increase of wind the New Brunswick System Operator, as Reliability Coordinator for the Maritimes Area, has the authority to curtail the variable generator as required.

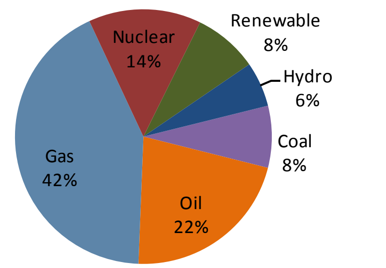
The Maritimes Area closely monitors air emissions and other environmental discharges to ensure compliance with standards and limits set forth by Canadian Federal and Provincial environmental regulations. For the 2012 Summer Operating Period, there may be occasions when some units are required to be derated in order to meet these regulations. However, these occasions are expected to be infrequent, of short duration and are not included in the summer assessment.

It is the responsibility of the generator owners to ensure that fuel supplies are adequate. The Maritimes Assessment Area does not consider potential fuel-supply interruptions in this assessment. The fuel supply in the Maritimes Assessment Area is very diverse and includes nuclear, natural gas, coal, oil (both light and residual), pet-coke, hydro, tidal, municipal waste, wind and wood.

NPCC-New England (ISO-NE)

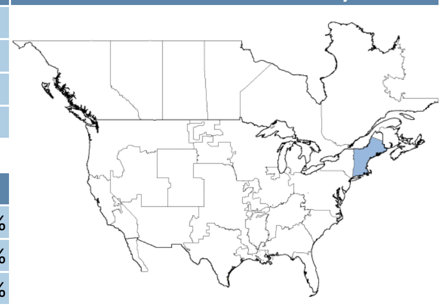
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	31,644	-
Future-Planned	137	-
Supply-Side Demand Response	1,128	-
Net Capacity Transactions	676	-
Anticipated	**33,585**	**26.92%**
Existing-Other and Future-Other	0	0
Prospective	**34,815**	**31.57%**
Reference Margin Level	-	**15.00%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**26,776**	**26,462**
Demand-Side Demand Response (2012)	-	978
Supply-Side Demand Response (2011)	2,035	-
Total Internal	**28,811**	**27,440**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	26,776	-1.17%
Actual Peak Demand	27,707	-4.49%
All-Time Summer Peak Demand (August 2, 2006)	28,130	-5.93%

Note: Additional information regarding the methods and assumptions used in the development of the NPCC-New England (ISO-NE) seasonal assessment can be found in Appendix I and on the NERC website.[85]

Assessment Area Highlights

Reserve Margins for the ISO New England (ISO-NE) Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

A total of 137 MW of capacity additions will be added prior to the 2012 summer. According to the ISO-NE's demand forecast, Total Internal Demand has decreased from 26,776 MW to 26,462 MW since the 2011 summer, a change of -1.2 percent. The forecasted demand values in this report take into account reductions due to passive demand resources (energy efficiency) with capacity supply obligations in ISO-NE's Forward Capacity Market. If the passive DR amounts of 978 MW in 2012 and 774 MW in 2011 were included in the forecast, the forecasted peak demands for 2012 and 2011 would be 27,440 MW and 27,550 MW, respectively.

During the 2012 summer, there are no projections of any significant transmission lines being out of service that could negatively impact regional reliability. Reduced and uncertain fuel supplies to Northeast Massachusetts/Boston resources will cause local capacity margins to be tight under high load conditions.

Planning Reserve Margins

ISO New England expects to have an adequate Planning Reserve Margin during the 2012 summer. The margins for Anticipated Capacity Resources range from a low of 26.9 percent in July to a high of 38.3

[85] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

percent in September. The main reason for this difference is the lower demand forecast in September, due to the typically cooler weather. Table 41 includes the 2011 and 2012 reserve margins for the New England Assessment Area.

Table 41: NPCC-New England (ISO-NE) Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	15.00%	15.00%
Existing-Certain & Net Firm Transactions	18.91%	26.40%
Anticipated	18.91%	26.92%
Prospective	18.95%	31.57%

New England does not have a fixed capacity or reserve margin requirement; rather it projects its capacity needs to meet the NPCC once in ten-year loss of load expectation (LOLE) resource planning reliability criterion. The capacity needs can vary from year to year depending on system conditions. Therefore, for the purposes of this report, the reference margin level is considered to be 15 percent, which is the target reserve margin assigned by NERC for predominantly thermal systems.

Demand

Last year's reference summer peak demand forecast was 26,776 MW. This was 1,671 MW (5.9 percent) lower than ISO-NE's reconstituted 2011 summer peak demand of 28,447 MW, which occurred on July 22. The metered peak demand of 27,707 MW reflects reductions of 710 MW due to real-time demand response resources that were activated that day as part of ISO-NE's Operating Procedure 4 (OP 4) and 30 MW of Real-Time Price Response. A key factor driving higher than forecasted peak demand was record heat within New England. Table 42 includes the demand forecasts for the 2011 and 2012 summers for the New England Assessment Area.

Table 42: NPCC-New England (ISO-NE) Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	26,776	26,462	-314	-1.17%
Total Internal	28,811	26,462	-2,349	-8.15%

The 2012 reference summer peak demand forecast of 26,462 MW is 314 MW (1.2 percent) lower than the 2011 summer peak demand forecast of 26,776 MW. The key factor leading to this decreased forecast is the slower than expected growth following the region-wide economic recession. State load growth is determined by each state's economic conditions/forecast and the relationship between the two, as captured by ISO-NE's econometric models and Moody's state economic forecasts.

Demand-Side Management

For the 2012 summer, there are 1,128 MW of active demand resources that are expected to be available on peak. Not included in this assessment is voluntary demand that may interrupt based on the price of wholesale energy. As of March 1, 2012, there were approximately 58 MW enrolled in the ISO-NE's price response program. Demand resources are treated as capacity in ISO-NE's FCM.

In addition to the active demand resources, ISO-NE has 978 MW of passive demand resources (*i.e.* energy efficiency & conservation), which are treated as demand reducers in this report. These include installed measures (*e.g.*, products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours. As noted in the Methods and Assumptions (Part II), ISO New England has established a new long-term forecast method for energy efficiency, which takes into account the potential impacts of growing Energy Efficiency/Conservation initiatives in the assessment area. However, in the near-term (*i.e.*, up to three years in the future), the amount of energy efficiency is based on capacity supply obligations in the FCM.

The 1,128 MW of active demand resources consist of real-time demand response and real-time emergency generation, which can be activated with the implementation of ISO-NE Operating Procedure No. 4 - Action during a Capacity Deficiency (OP 4). These active DR can be used to help mitigate an actual or anticipated capacity deficiency. OP 4 Action 2 is the dispatch of Real-Time Demand Resources, which is implemented in order to manage operating reserve requirements. Action 6, which is the dispatch of Real-Time Emergency Generation Resources, may be implemented to maintain 10-minute reserve. Figure 35 and Table 35 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the New England Assessment Area.

Figure 35: NPCC-New England (ISO-NE) Demand Response

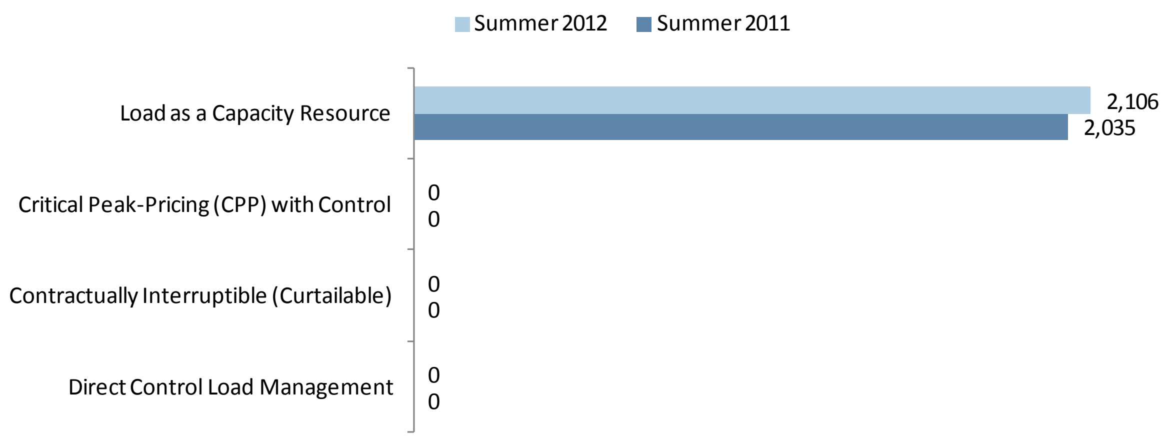


Table 43: NPCC-New England (ISO-NE) Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	0	0	0
Contractually Interruptible (Curtailable)	0	0	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	2,035	978	1,128
Total Demand Response	**2,035**	**978**	**1,128**
Percentage of Total Internal Demand	**7.06%**	**3.70%**	**4.26%**

Some assets in the real-time demand response programs are under direct load control by the load response providers (LRP). The LRP implements direct load control of these assets upon dispatch instructions from ISO-NE, for example, interruption of central air conditioning systems in residential and commercial facilities.

The ISO presently does not permit demand response to be used for Ancillary Services. However, the option of allowing demand response to participate in the reserve market, and possibly for frequency regulation, is something that may be considered in the future.

Generation

ISO New England has adequate capacity consisting of Existing-Certain generation (31,644 MW), Future-Planned generation (137 MW), demand resources (1,128 MW) and net imports (676 MW) to meet the demand of 26,462 MW throughout the summer season. The lowest Anticipated Reserve Margin of 7,123 MW (26.9 percent) occurs in the month of July. ISO New England ensures that it has enough capacity to meet system needs through its Forward Capacity Market (FCM). The amount of capacity that is needed to meet the once in ten-year disconnection of Firm load resource planning reliability criterion is purchased through annual auctions three years in advance of the year of interest. After this primary auction, there are Annual Reconfiguration Auctions prior to the commencement year, in order to re-adjust installed capacity purchases and ensure that adequate capacity will be purchased to meet system needs.

ISO-NE's Existing-Certain generating capacity during the month of July amounts to 31,644 MW based on Summer Seasonal Claimed Capability ratings. An additional 1,230 MW of capacity consists of wind, solar and hydro derates, and as well as 188 MW of planned generator maintenance. There is no Existing-Inoperable capacity. Table 44 provides the resource projections for the 2011 and 2012 summers.

Table 44: NPCC-New England (ISO-NE) Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	29,590	31,644
Future-Planned	0	137
Supply-Side Demand Response	2,035	1,128
Net Capacity Transactions	1,136	676
Anticipated	**32,761**	**33,585**
Existing-Other and Future-Other	0	0
Prospective	**32,761**	**34,815**

Natural gas-fired generation represents the largest component of ISO New England's total installed capacity at 43.0 percent (13,764 MW), followed by oil-fired generation at 21.6 percent (6,895 MW), nuclear generation at 14.5 percent (4,628 MW), and coal at 7.8 percent (2,484 MW). Hydroelectric capacity (1,483 MW) and pumped-storage capacity (1,698 MW) make up 4.6 percent and 5.3 percent of the total, respectively. The remaining 3.2 percent of capacity consists of renewable capacity such as that provided by wind or biomass facilities.

A total of 66 MW of new generation has been installed since last summer. Most of that capacity (62 MW summer capability, or 217 MW nameplate rating) consists of wind facilities. With these additions, the total 2012 summer on-peak wind capacity is 97 MW. Another 2 MW of the new generation is solar capacity, bringing the total solar capacity to 5 MW. It is expected that 130 MW of gas-fired combustion turbines and an 8 MW fuel cell plant will become commercial before or during the 2012 summer.

AES Thames, a 181 MW coal plant, ceased operation in early 2011. Its capability is currently zero and is not included in the reserve margin calculations. The reserve margin for summer 2012 is above the Reference Margin Level without AES Thames; therefore the loss of this plant is not a concern.

ISO-NE has not approved any noteworthy long-term generator outages that would impact the 2012 summer period. Additionally, ISO-NE does not have any information about behind-the-meter generation, other than Real-Time Emergency Generation (RTEG). RTEG is a form of distributed generation that is classified as an active demand resource in the Forward Capacity Market, and is dispatched by ISO-NE during implementation of OP 4. A total of 435 MW of RTEG has an obligation to provide capacity in summer 2012.

Within the Existing-Certain category, approximately 97 MW of capacity is wind generation that is expected to be available at the time of peak demand. This reflects a 469 MW derate on-peak, from the total nameplate capability of 566 MW. Solar generation makes up 5 MW of on-peak capacity, derated from its nameplate capacity of 18 MW. Existing-Certain capacity also includes 1,483 MW of hydro-electric resources. This reflects a 560 MW derate on-peak, from the total nameplate capability of 2,043 MW. Biomass capacity in the Existing-Certain category totals 907 MW. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 36 and Table 45.

Figure 36: NPCC-New England (ISO-NE) Renewable Generation

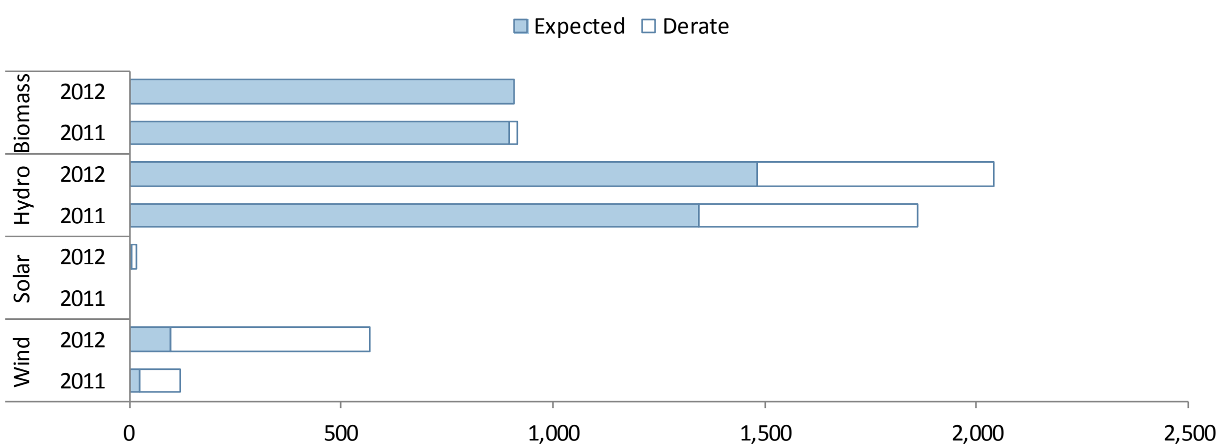


Table 45: NPCC-New England (ISO-NE) Renewable Resources

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	26	97	0	5	1,346	1,483	897	907
Derate	93	469	0	13	517	560	18	0
Nameplate	**119**	**566**	**0**	**18**	**1,863**	**2,043**	**915**	**907**

ISO-NE continues to integrate new power supply sources, including new variable resources, into the network. All new resources are studied in detail by ISO-NE Operations Engineering prior to commercial operation. They are all integrated through the use of operating guides / interface limits and through ISO-NE's Energy Management System (EMS).

Capacity Transactions

The forecast for 2012 summer on-peak Firm capacity imports is 776 MW. These Firm capacity imports, which include 465 MW from Hydro-Québec and 311 MW from New York, have been contracted for delivery within the 2012/2013 FCM Capability Period. Additionally, there are 100 MW of net Firm exports projected for the 2012 summer. New England's capacity transactions for the 2012 summer are shown in Table 46.

Table 46: NPCC-New England (ISO-NE) Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	776	100	676
Expected	0	0	0
Total	**776**	**100**	**676**

The 435 MW of Real-Time Emergency Generation (RTEG) with capacity obligations in ISO-NE's Forward Capacity Market are used for meeting the Reference Margin Level. RTEG is treated as a demand resource that can be called as part of OP 4 Action 6.

Transmission

All significant transmission lines and transformers are expected to be in service through the 2012 summer season with the exception of scheduled transmission projects in Maine as part of the Maine Power Reliability Program (MPRP) construction. In the event of a major unplanned outage of significant transmission facilities and the scheduling of MPRP construction outages, operating procedures will be in place to maintain system reliability. As a result, there are no expected project delays or temporary service outages for ISO-NE transmission facilities that would impact reliability during the 2012 summer.

Operations

There are no extreme conditions that are expected to adversely impact system reliability during the 2012 summer period. Therefore, no special operating studies are needed beyond the normal long- and short-term studies that are performed constantly to assess system conditions for each period during the year. Reduced and uncertain fuel supplies to Northeast Massachusetts/Boston resources will cause local capacity margins to be tight under high load conditions.

The implementation of the FCM has enhanced the integration of demand resources into system operations. ISO New England has two real-time demand resource programs that can be used to manage load and reserves as part of implementation of OP 4. The first program is focused on load response and is used early in OP 4. The second is emergency generation (RTEG), which is accessed in a later OP 4 action. All of these resources are audited in both the summer and winter period each year for their ability to perform. Based on DR audits in summer 2011 and the response of Active DR during the July 22, 2011 OP 4 event, ISO-NE expects that approximately 95 percent of DR capacity will perform. In addition, each resource submits the hourly status of their capability to the ISO, and the system operators are able to view that capability in real-time. Finally, the operators are provided with telemetry from each resource to monitor the real-time performance of the resources in relation to their capacity supply obligations.

There are no environmental or regulatory restrictions currently being discussed or forecast for the region that may significantly impact system reliability. In the past, environmental restrictions on coastal or river-based generating units due to cooling water discharge temperatures during extremely hot summer days and/or low hydrological conditions have resulted in temporary capacity reductions ranging from 50 MW to 500 MW. It is expected that such temporary reductions will be significantly reduced in the future due to the installation of closed loop cooling systems.

The regional gas pipelines and local gas distribution companies (LDCs) communicate with ISO-NE to identify any planned maintenance that may impact fuel deliveries to the power sector. ISO-NE was informed, well in advance, of a four-day, planned outage of a regional gas pipeline that is scheduled for early June. ISO-NE and the owners of the pipeline are working together to minimize the impacts from this planned outage, as well as accommodate other gas sector maintenance and inspection outages planned during the spring, summer, and fall timeframes.

Historically, fuel supply and delivery options have been readily available to generators within New England during the summer months. For the summer of 2012, ISO New England does not foresee system-wide fuel supply or delivery constraints. In the Northeast Massachusetts/Boston area, reduced and uncertain fuel supplies to Northeast Massachusetts /Boston resources will cause localized capacity margins to be tight under high load conditions. In addition, New England's dependence on natural gas to fire combined cycle generation requires close coordination with natural gas pipeline companies as well as major LNG companies as part of its communications protocol.

Vulnerability Assessment

New England has not been undergoing a drought and drought conditions are not forecasted for the near future. Overall, no significant generating facilities are projected to be out of service during the 2012 summer peak demand period.

Since demand resources with obligations in the FCM risk being penalized for under-performance, ISO-NE anticipates that the DR response rate will be at or very close to the full capacity obligation. This has been confirmed by audits of Active DR in summer 2011, when 95 percent of DR capacity responded, as well as during the July 22, 2011 OP 4 event when approximately 100 percent of RTDR responded. This level of response may not occur during an extended period of dispatch; such a condition has not yet occurred, so there is no data on which to base assumptions.

Wind generation capacity in ISO-NE is growing, with approximately 566 MW installed and commercially operational capacity as of March 2012. This growth in wind power along with the recommendations developed during the New England Wind Integration Study (NEWIS) has led ISO-NE to plan for and implement a centralized wind power forecasting service. The Wind Power Forecast Integration Project (WPFIP) will be implemented in two phases. Phase 1 of the WPFIP, scheduled to be completed in the first quarter of 2013, focuses on setting up the communications and database systems to be able to deliver wind power forecasting related data from wind plants through ISO-NE to the wind power forecaster service and vice-versa, as well as developing situational awareness displays and functions to enhance ISO operator situational awareness for wind power, and incorporating the forecasts into the day-ahead unit commitment and periodic unit commitment refinement processes.

No special protection systems have been installed since last summer in New England. Additionally, there are no reductions or retirements scheduled within the 2012 summer period that relate to compliance with environmental regulations.

ISO-NE tracks environmental regulations and projects the impacts of potential regulations in its long-term planning studies. In the upcoming three-year period, any generator reductions or retirements would be reflected in the FCM obligations.

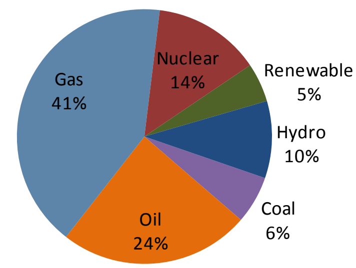
Since the FCM requires that adequate resources are purchased to meet the Installed Capacity Requirement, any capacity requirements that can potentially not be met due to long-term outages can be supplied by other FCM resources.

ISO-NE routinely gauges the impacts that fuel supply disruptions could have upon system or subregional reliability. Because natural gas is the predominant fuel used to produce electricity in New England, ISO-NE monitors the regional natural gas pipeline systems, via their electronic bulletin board postings, to ensure that emerging gas supply or delivery issues can be incorporated into the daily or next-day operating plans. Should issues arise that may impact natural gas deliveries to regional power generators, ISO-NE has communication protocols in place with the Gas Control Centers of regional pipelines and LDCs, in order to quickly understand the emerging situation and then implement mitigation measures. In the case of regional fuel supply deficiencies, ISO-NE's Operating Procedure No. 21 - Action during an Energy Emergency (OP 21) is used to facilitate communication with market participants in an attempt to bring more fuel supply to the system. Historically, fuel supply and delivery options have been readily available to generators within New England during the summer months. For the summer of 2012, ISO New England does not foresee system-wide fuel supply or delivery constraints. In the Northeast Massachusetts/Boston area, reduced and uncertain fuel supplies to Northeast Massachusetts /Boston resources will cause localized capacity margins to be tight under high load conditions. In addition, New England's dependence on natural gas to fire combined cycle generation requires close coordination with natural gas pipeline companies as well as major LNG companies as part of its communications protocol.

NPCC-New York (NYISO)

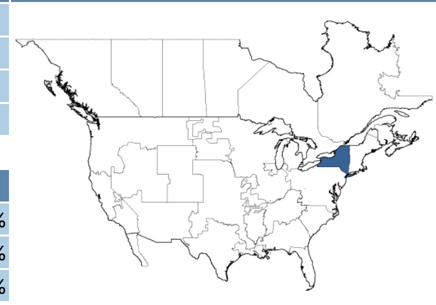
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	34,908	-
Future-Planned	0	-
Supply-Side Demand Response	2,165	-
Net Capacity Transactions	1951	-
Anticipated	**39,024**	**17.21%**
Existing-Other and Future-Other	0	-
Prospective	**39,024**	**17.21%**
Reference Margin Level	-	**16.00%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**32,712**	**33,295**
Demand-Side Demand Response (2012)	-	0
Supply-Side Demand Response (2011)	2,053	-
Total Internal	**34,765**	**33,295**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	32,712	1.8%
Actual Peak Demand	33,865	-1.7%
All-Time Summer Peak Demand (August 2, 2006)	33,939	-1.9%

Note: Additional information regarding the methods and assumptions used in the development of the NPCC-New York (NYISO) seasonal assessment can be found in Appendix I and on the NERC website.[86]

Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the New York Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The reserve margins for the New York Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

A total of 0 MW of capacity additions will be added during the 2012 summer. However, a total of 1,505 MW of retirements and protective layups of generation have been implemented since summer 2011. According to the NYISO's demand forecast, Total Internal Demand has increased from 32,712 MW to 33,295 MW since the 2011 summer. This equates to an annual growth rate of 1.8 percent.

Planning Reserve Margins

The NYISO is projecting an adequate Planning Reserve Margin during the 2012 summer, as presented in Table 47. The Anticipated Reserve Margins range from 17.2 percent to 42.8 percent during the summer months. The Reference Margin Level is 16.0 percent.

The NYISO projects adequate levels of installed capacity and demand response. Unforced Forced outages could reduce available installed capacity but that is not anticipated at this time

[86] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

Table 47: NPCC-New York (NYISO) Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	15.50%	16.00%
Existing-Certain & Net Firm Transactions	19.15%	17.21%
Anticipated	19.15%	17.21%
Prospective	19.15%	17.21%

The NYISO projects adequate levels of installed capacity and demand response. Forced outages could reduce available installed capacity but that is not anticipated at this time.

Demand

The peak demand forecast for summer 2011 was 32,712 MW. The actual peak demand was 33,865 MW on July 22, 2011, hour beginning 3:00 PM. Demand response programs resulted in a load curtailment estimated to be 1,431 MW. The load without the curtailment would therefore have been 35,296 MW. Extreme weather conditions were present throughout the entire state on the day of the peak, with weather conditions exceeding the 90th percentile of typical peak-producing weather conditions. The weather adjusted load at normal weather conditions was determined to be 33,018 MW, with downward adjustment of 2,278 MW due to weather. The weather-adjusted peak load was 306 MW (0.9 percent) above the forecast. Most of this is attributed to the return to service of large industrial load due to improved economic conditions.

As presented in Table 48, the 2012 coincident peak demand forecast is 33,295 MW. The increase in the forecast since 2011 (583 MW) summer is due primarily to a return to service of large industrial loads and a gradual improvement in economic conditions throughout the state. There are no changes or enhancements to methods used in the assessment forecast since last summer.

Table 48: NPCC-New York (NYISO) Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	32,712	33,295	583	1.78%
Total Internal	34,765	33,295	-1,470	-4.23%

Demand-Side Management

The total amount of Demand Response and Energy Efficiency/Conservation that is expected to be in available on peak for the 2012 summer includes Load as a Capacity resource: 2,165 MW. Additionally 257 MW of Voluntary Energy Demand Response is also projected to be available. Figure 37 and Table 49 present the demand response forecasted for the 2011 and 2012 summer peaks in the New York Assessment Area.

Figure 37: NPCC-New York (NYISO) Demand Response

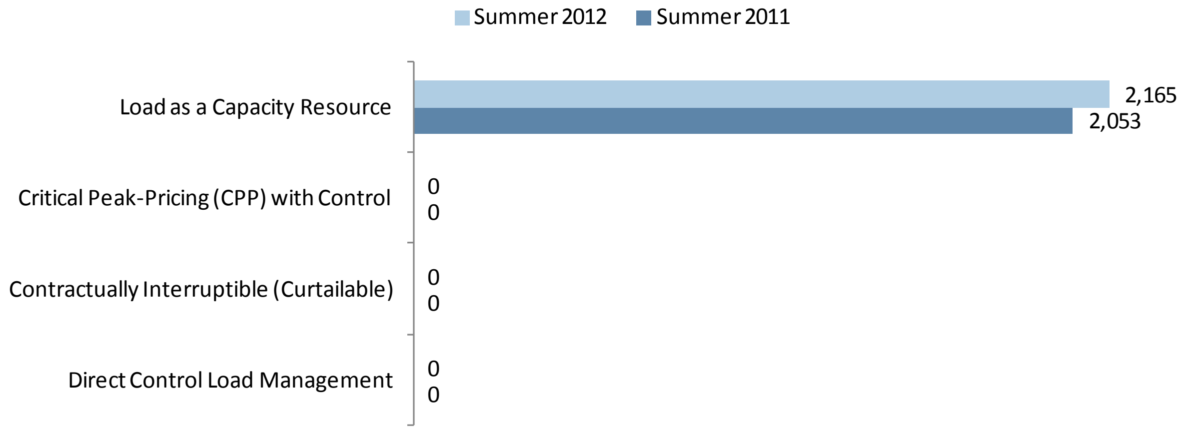


Table 49: NPCC-New York (NYISO) Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	0	0	0
Contractually Interruptible (Curtailable)	0	0	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	2,053	0	2,165
Total Demand Response	**2,053**	**0**	**2,165**
Percentage of Total Internal Demand	**5.91%**	**0.00%**	**6.50%**

Demand response resources in the Special Case Resource (reported under Load as a Capacity Resource) and Emergency Demand Response Programs (reported as Voluntary Energy Demand Response) are deployed for forecast or actual operating reserve shortages or other emergency reliability needs.

The most recent status on existing and projected Demand-Side Management programs includes:

- Energy Efficiency/Conservation programs are currently offered throughout the state by a number of utilities and state agencies for a cross-section of market segments and energy efficiency measures.
- No changes anticipated this year for Total Dispatchable and Controllable Demand Response.
- For Demand Response used for Ancillary Services Communication improvements have been made by the NYISO, to allow direct communication of dispatch signals to Demand Response providing Ancillary Services and market rules for allowing aggregations to provide operating reserves and regulation service are expected to reduce barriers to entry.

Generation

For the 2012 summer season the NYISO projects 34,908 MW of Existing-Certain capacity for the forecasted peak month.

Traditionally, New York generation mix has been dependent on fossil fuels for the largest portion of the installed capacity. Recent capacity additions or enhancements now available use natural gas as the primary fuel. While some existing generators in southeastern New York have "dual-fuel" capability, use of residual or distillate oil as an alternate may be limited by environmental regulations. Adequate supplies of all fuel types are expected to be available for the summer period.

Since the 2011 summer season the New York control area has added 456 MW of dual-fuel (oil or gas) generation, 20 MW of solar generation, 13 MW of wind generation, 5 MW of landfill gas generation and 1 MW of run-of-river hydro generation that are considered Existing-Certain resources. There are no planned additions during the 2012 summer season.

There were fourteen unit retirements in New York since the 2011 summer season that will impact 2012 summer generation. Protective layups and retirements are included below:

- Astoria Units 2 and 4 (180 and 380 MW respectively);
- Gowanus Barge Units 1 and 4 (160 MW each);
- Ravenswood GT 3 and 4 (43 MW)
- Astoria GTs 10 and 11 (32 MW each)
- Barrett Unit #7 (20 MW),
- Binghamton Cogen (48 MW),
- Beebee CT 13 (18 MW),
- Far Rockaway (105 MW),
- Glenwood units 4 and 5 (114 MW each)

Total nameplate retirements amount to 1,403 MW. Since the NYISO projects adequate resources available for the 2012 summer season, no specific measures are necessary and no potential reliability issues are foreseen.

The following factors are not expected to cause any short-term impacts during the 2012 summer season: generator up-rates; units taken out of service; units being brought into service; long-term outages; behind-the-meter generation, or “non-traditional” generation. Table 50 includes resource projections for the 2011 and 2012 summers.

Table 50: NPCC-New York (NYISO) Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	36,700	34,908
Future-Planned	0	0
Supply-Side Demand Response	2,053	2,165
Net Capacity Transactions	222	1,951
Anticipated	**38,975**	**39,024**
Existing-Other and Future-Other	0	0
Prospective	**38,975**	**39,024**

There is nameplate capacity of 1,363 MW of wind generation in the New York control area with 248.1 MW of expected on-peak capacity. There is nameplate capacity of 32 MW of solar generation in the New York control area with 20.8 MW of expected on-peak capacity. There is nameplate capacity of 4,676 MW of large hydro and 1,005 MW of run-of-river hydro generation in the New York control area with 4,582 MW and 552 MW of expected on-peak capacity, respectively. There is nameplate capacity of 432 MW of biomass generation in the New York control area with 389 MW of expected on-peak capacity.

Wind generation is derated 81.9 percent. Solar generation is derated 35 percent. Large hydro is derated 2 percent while run-of-river hydro is derated 45 percent. Landfill gas units are derated 16.6 percent while refuse and wood biomass units are derated 8.1 percent. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 38 and Table 51.

Figure 38: NPCC-New York (NYISO) Renewable Generation

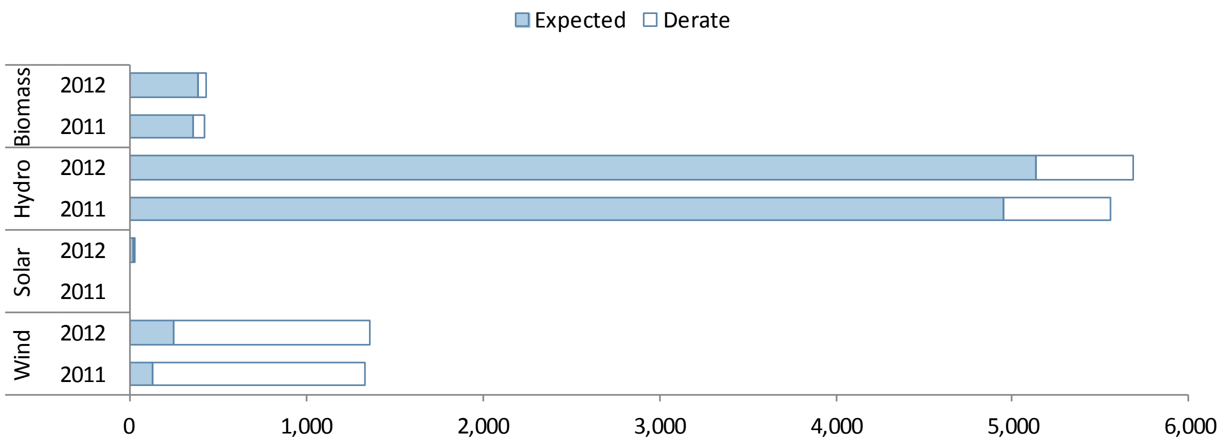


Table 51: NPCC-New York (NYISO) Renewable Generation

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	133	248	0	21	4,951	5,135	358	390
Derate	1,196	1,115	0	11	603	546	63	42
Nameplate	**1,329**	**1,363**	**0**	**32**	**5,554**	**5,681**	**421**	**432**

NYISO has incorporated variable resources into the dispatch software, along with Limited Energy Storage Resources, (flywheel and batteries). These resources are integrated such that no unique operational procedures are required.

Capacity Transactions

The NYISO projects net imports of committed external resources into the New York Balancing Authority area of 1,951 MW during summer 2012. Due to NYISO market rules the specific projected sales and purchases are considered confidential non-public information and cannot be explicitly indicated in this assessment. On-peak capacity transactions projected for the 2012 summer are included in Table 52.

Table 52: NPCC-New York (NYISO) Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	1,951	0	1,951
Expected	0	0	0
Total	**1,951**	**0**	**1,951**

Capacity purchases in New York are not required to have accompanying Firm transmission reservations, but adequate transmission rights must be available to assure delivery to New York when scheduled. External capacity is also subject to external availability rights. Availability on the import interface is offered on a first-come first-serve basis. The total capacity purchased for this summer operating period may increase since there remains both time and external rights availability.

Due to NYISO market rules, information on specific import and export transactions is considered confidential. Information on the aggregated or net expected capacity imports and exports during peak summer conditions is not yet known. Capacity is traded in the NYISO market as a monthly product, and total imports and exports are not finalized until shortly before the month begins. NYISO does not rely on external resources for emergency assistance.

Transmission

There are no project delays or service outages that will impact reliability during the 2012 summer. The Beck-Packard BP76 230 kV circuit is expected to remain out of service through the summer period. It is not expected to have a significant impact on system reliability.

An Astoria East 345/138 kV transformer and a 138 kV phase shifter will be installed in the New York City area to assure local area reliability for the conditions of a generator retirement (Astoria 2) and simultaneous long-term forced outage of an adjacent generator proactive layup (Astoria 4).

Adjacent circuits on a common tower out of Oakdale 345 kV station will be separated to assure local area reliability to accommodate the retirement of a local generator.

The Beck-Packard 76 (BP76) 230 kV line will be out of service for the summer period. In addition the Massena-Moses 2 (MMS-2) 765/230 kV line will be out of service for the summer period.

Operations

NYISO conducts capability assessments studies. There were no unique operational problems observed from these studies

NYISO has incorporated variable resources into the dispatch software, along with Limited Energy Storage Resources, (flywheel and batteries). These resources are integrated such that no unique operational procedures are required. NYISO does not anticipate any reliability issues from minimum demand or over generation.

The use of Demand resources are fully integrated into the policies and procedures of the NYISO. The program design promotes participation and the ISO expectation is for full participation. Further control actions are outlined in ISO policies and procedures. There are no limits to the number of times a resource can be called upon to provide response.

High capacity factors on certain New York City (NYC) peaking units could result in possible violations of their daily NOx emission limits if they were to fully respond to the NYISO dispatch signals. Significant run time on peaking units, indicating the potential for a violation, could be the result of long duration hot weather events or loss of significant generation or transmission assets in NYC. In 2001, the New York State Department of Environmental Conservation (DEC) extended the agreement it had previously with the New York Power Pool to address the potential violation of NOx and opacity regulations if the NYISO were required to keep these peaking units operating to avoid the loss of load. Pursuant to the terms of this agreement (DEC, Declaratory Order # 19-12) if the NYISO were to issue an instruction to a Generator to go to maximum capability, in order to avoid loss of load, any violations of NOx RACT emission limits or opacity requirements imposed under DEC regulations would be subject to the affirmative defense for emergency conditions. This determination is limited to circumstances where the maximum capability requested by the NYISO would involve the generation of the highest level of electrical power achievable by the subject Generators with the continued use of properly maintained and operating pollution control equipment required by all applicable air pollution control requirements At this time NYISO does not anticipate any unusual conditions that will impact reliability

Vulnerability Assessment

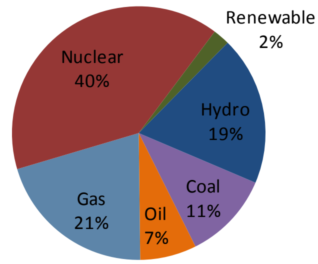
For 2012 summer there are no specific operational concerns for extended drought conditions, long-term generator outages, unavailable demand response or increases in variable generation. Also, there are no anticipated impacts from environmental regulations this season. No special protection systems have been installed on the New York system since last summer.

NYISO has adopted the New York State Gas-Electric Coordination Protocol as Appendix BB to its Open Access Transmission Tariff (OATT). This Coordination Protocol applies to circumstances in which the NYISO has determined (for the bulk power system) or a Transmission Owner has determined (for the local power system) that the loss of a Generator due to a Gas System Event would likely lead to the loss of Firm load. This Coordination Protocol also applies to communications following the declaration of an Operational Flow Order or an Emergency Energy Alert (EEA). There are no anticipated fuel delivery problems for this summer operating period.

NPCC-Ontario (IESO)

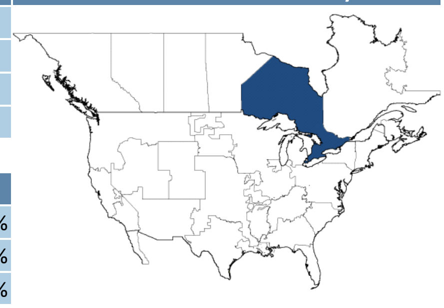
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	27,955	-
Future-Planned	1,170	-
Supply-Side Demand Response	1,326	-
Net Capacity Transactions	0	-
Anticipated	**30,451**	**30.08%**
Existing-Other and Future-Other	6,284	-
Prospective	**36,735**	**56.92%**
Reference Margin Level	-	**20.40%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**23,561**	**23,409**
Demand-Side Demand Response (2012)	-	0
Supply-Side Demand Response (2011)	1,235	-
Total Internal	**24,796**	**23,409**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	23,561	-0.65%
Actual Peak Demand	25,450	-8.02%
All-Time Summer Peak Demand (August 1, 2006)	27,005	-13.32%

Note: Additional information regarding the methods and assumptions used in the development of the NPCC-Ontario (IESO) seasonal assessment can be found in Appendix I and on the NERC website.[87]

Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for assessing the reliability of resources, demand, and transmission infrastructure in the Ontario Assessment Area. Generation data was collected from individual entities and aggregated using a bottom-up approach. Demand data projections were based on economic indicators, long-term weather forecasts, and historic load data, using a top to bottom approach.

The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer. A total of 1,357 MW of nameplate capacity will be added before and during the 2012 summer. According to the Ontario demand forecast, Total Internal Demand is expected to decrease from 23,501 MW (weather-corrected actual demand) to 23,409 MW since the 2011 summer. This equates to an annual growth rate of -0.4 percent.

Planning Reserve Margins

Ontario is projecting adequate Planning Reserve Margins during the 2012 summer. Anticipated Planning Reserves, determined on the basis of the IESO's requirements for Ontario self-sufficiency, are above the Reference Margin Level over this period (for normal weather conditions). The Reference Margin Level for Ontario is 20.4 percent. Table 53 includes the 2011 and 2012 reserve margins for the Ontario Assessment Area.

[87] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

Table 53: NPCC-Ontario (IESO) Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	21.30%	20.40%
Existing-Certain & Net Firm Transactions	31.75%	25.08%
Anticipated	31.80%	30.08%
Prospective	37.37%	56.92%

During the summer of 2012, there will be more than 1,350 MW of capacity added to the grid, comprising of one refurbished nuclear unit, with a capacity of 750 MW returning to service, approximately 400 MW of new gas-fired generation and more than 200 MW of new grid-connected renewable generation. Many of these projects have started their commissioning or at an advanced construction stage. Though some delays in Future-Planned capacity are still possible, Ontario meets the Reference Margin Level, with Existing-Certain capacity.

The IESO prepares for extreme weather conditions during the summer by executing planning studies that use the most severe weather experienced since 1970. These studies show that Ontario will have sufficient reserves throughout the entire 2012 summer period. Available operational and market measures, as well as interconnection capabilities are considered sufficient to meet the peak demands during the 2012 summer.

Demand

Last summer's peak demand forecast was 23,561 MW (weather-normalized) and 25,941 MW (extreme weather). The actual (non-weather-corrected) peak demand was 25,450 MW. Demand was significantly higher than the weather-normalized forecast, with actual conditions meeting those of the IESO extreme weather scenario. Once the impact of demand response is considered, the "reconstituted" peak would have been 25,858 MW. This would mean the extreme weather forecast had a mean absolute percentage error of 0.3 percent, compared to the reconstituted demand.

The 2012 summer peak demand forecast is 23,409 MW, which is lower than the peak demand forecast for the summer of 2011. Peak demand is expected to be lower due to three main factors:

- The economy remains stagnant with little growth in the industrial sector;
- Residential and commercial load will increase due additional construction activity;
- Underlying load growth will be more than offset by the increase in embedded generation, conservation and customers facing time-of-use rates.

Table 54 includes the demand forecasts for the 2011 and 2012 summers for the Ontario Assessment Area.

Table 54: NPCC-Ontario (IESO) Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	23,561	23,409	-152	-0.65%
Total Internal	23,561	23,409	-152	-0.65%

The economic outlook for Canada calls for modest growth throughout 2012. Ontario is expected to lag behind national growth as its export-oriented manufacturing sector is highly dependent on U.S. and global growth. While other oil producing provinces will lead the nation in growth, Ontario will be impacted by the upward pressure that oil exports put on the Canadian dollar. Accordingly, the economic outlook varies according to the economic characteristics throughout the province – and throughout Canada. Areas that rely on the forestry industry have been negatively impacted by the high Canadian dollar and subsequent lower demand for paper products. Those areas with a large manufacturing concentration have stabilized, but have not returned to the prerecession growth levels.

On a positive note, the mining and petrochemical sectors have remained strong, as foreign demand has remained untarnished. Economic conditions in Toronto are also expected to improve, due to its diverse economy and dominance as the nation's largest city.

Economic growth is not directly aligned with electricity growth, due to structural changes in the Ontario economy. Many of the growth areas in the economy are in the service sector, which does not typically consume large volumes of electricity. In addition, demand from the traditional energy-intensive resource and manufacturing sectors is expected to remain unaffected.

Demand-Side Management

The IESO has just over 1,850 MW of demand response capacity of which 1,326 MW is deemed to be reliably available at the time of system peak. Figure 39 and Table 55 present the demand response forecasted for the 2011 and 2012 summer peaks in the Ontario Assessment Area.

There are limited restrictions on how many times Demand Response can be deployed, as there are price and demand triggers that must both be met to deploy these resources. These triggers are calculated in advance to meet a certain number of activations per month.

Figure 39: NPCC-Ontario (IESO) Demand Response

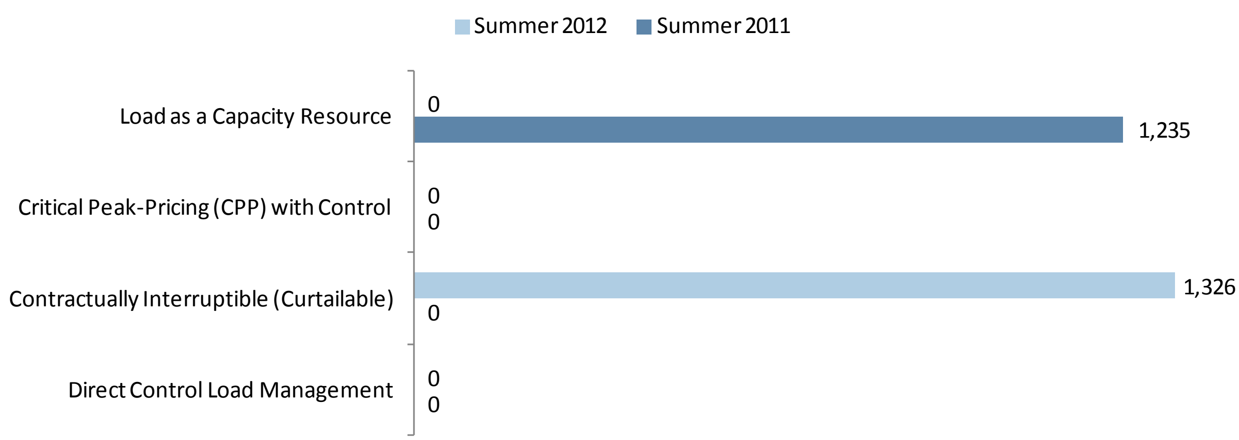


Table 55: NPCC-Ontario (IESO) Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource) 2011	Demand-Side (Load-Modifying) 2012	Supply-Side (Capacity Resource) 2012
Direct Control Load Management	0	0	0
Contractually Interruptible (Curtailable)	0	0	1,326
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	1,235	0	0
Total Demand Response	**1,235**	**0**	**1,326**
Percentage of Total Internal Demand	**5.24%**	**0.00%**	**5.66%**

The majority of Ontario's demand response programs are dispatchable, market driven programs. The two main initiatives are Dispatchable Loads and Demand Response 3 (DR3). The Dispatchable Loads bid into the market and are dispatched off like any resource. This program has a total capacity of roughly 900 MW. The DR3 program contracts loads that are dispatched off the system based on the supply cushion – the difference between demand and supply. This program has a capacity of 525 MW. Four other programs provide an additional 425 MW of capacity; none of the IESO's demand response programs are used for Ancillary Services.

There are a number of conservation initiatives under development by distributors and the Ontario Power Authority, which are decremented from demand. However, none of these are included as demand response programs.

Generation

The amount of Existing-Certain and Existing-Other on-peak resources is 27,955 MW and 6,284 MW, respectively. Existing-Inoperable totals 27.5 MW. The primary fuel of existing resources by installed capacity is nuclear (34 percent), followed by gas/oil (28 percent) and hydroelectric (23 percent). 13 MW of Existing-Certain wind generation has been added since the prior season. Table 56 includes projections of Ontario resources for the 2011 and 2012 summer.

Table 56: NPCC-Ontario (IESO) Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	29,807	27,955
Future-Planned	12	1,170
Supply-Side Demand Response	1,235	1,326
Net Capacity Transactions	0	0
Anticipated	**31,054**	**30,451**
Existing-Other and Future-Other	1,312	6,284
Prospective	**32,366**	**36,735**

Leading up to the 2012 summer season, Ontario projects the addition of two wind farms (214 MW) and one new gas-fired generator (393 MW). A nuclear unit refurbishment (Bruce G1 750 MW) is expected to be completed during the summer period, adding an additional 750 MW of capacity. These projects will provide an additional nameplate capacity of 1,357 MW, of which 1,170 MW is projected to be available during the summer peak.

In December 2011, the shutdown of two southern Ontario coal units resulted in a decrease of 980 MW in Existing-Certain capacity since last season. To compensate for the reactive output that was lost with the closure of these units, dynamic control facilities at Detweiler and Nanticoke transformer stations were placed in service. Since the last seasonal assessment (Winter 2011/2012), a 99 MW wind farm has come in to service.

Since the summer of 2011 and prior to the summer of 2012, 600 MW of new embedded generation contracted to begin commercial operation. The Ontario Power Authority (OPA) provides the IESO with information for embedded generation. Based on the fuel type, a production estimate is generated and applied in the form of a demand reduction starting on the in service date specified in the contract.

A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 40 and Table 57.

Figure 40: NPCC-Ontario (IESO) Renewable Generation

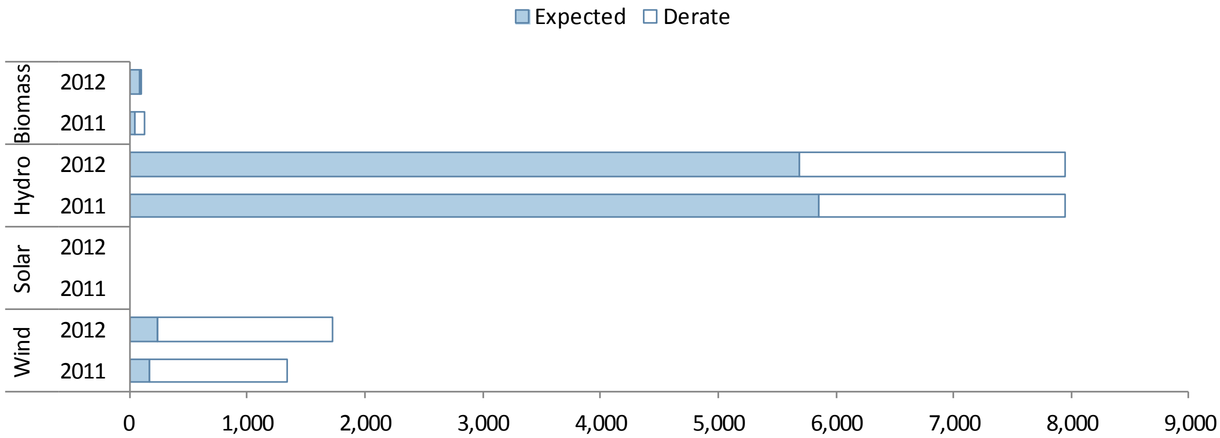


Table 57: NPCC-Ontario (IESO) Renewable Generation

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	173	230	0	0	5,852	5,694	37	81
Derate	1,160	1,496	0	0	2,095	2,253	85	13
Nameplate	**1,334**	**1,725**	**0**	**0**	**7,947**	**7,947**	**122**	**95**

To model wind resources in the adequacy assessments, the IESO uses an estimated wind capacity contribution during peak demand hours. This model captures wind output during the top five contiguous daily peak demand hours for the winter and summer seasons, as well as monthly shoulder periods. Two sets of wind data are considered: simulated wind data over a fixed 10-year history, and actual wind farm output data collected since March 2006. A conservative approach is employed, which selects the lesser value of the two data sets (simulated vs. actual) for each winter/summer season and shoulder period month. For the seasonal assessments, wind capacity contribution is represented deterministically, by selecting median values observed during the winter and summer seasons and shoulder period months.

IESO resource adequacy assessments include hydroelectric generation capacity contributions based on median historical values of hydroelectric production plus operating reserve provided during weekday peak demand hours. Hydroelectric production is monitored on a monthly basis and due allowance is made for deviations from the median historical conditions. Deviations from the median are not anticipated at this time for the upcoming summer. In the operating timeframe, water resources are managed by market participants through market offers to meet the hourly demands of the day. Since most hydro storage facilities are energy limited, hydroelectric operators identify weekly and daily limitations for near-term planning in advance of real-time operations.

The forecast of hydro generation was enhanced in November 2011 to account for the impact of project related long-duration outages (*e.g.* hydro facility expansions and major equipment replacements and/or repairs) that occur less frequently – but take longer – than regular maintenance. The hydroelectric performance is monitored on a monthly basis and adjustments may also be made to the forecast values when water conditions drive expectations of higher or lower output that deviates from median values by approximately 500 MW for two consecutive months.

The Stakeholder Engagement (SE) 91 process is currently underway to address the need for forecasting, visibility and dispatch of renewable resources. The results are expected after the summer season.

Capacity Transactions

In its determination of resource adequacy, the IESO plans for Ontario to meet NPCC Regional criteria without reliance on external resources. There are no Firm or Expected imports or exports identified for the 2021 summer.

For use during daily operation, operating agreements between the IESO and neighboring jurisdictions in NPCC, RFC and MRO include contractual provisions for emergency imports directly by the IESO. IESO also participates in a shared activation of reserve group which includes PJM, NYISO, ISO-NE and New Brunswick. No emergency generation is assumed to be available to meet Ontario's Reference Margin Level.

Transmission

Planned outages may result in some transfer capability reductions of the transmission circuits but are not expected to have any impact on the load supply. The completion date for transmission reinforcements from the Niagara region into the Hamilton-Burlington area continues to be delayed. This delay could impact the ability to import at Niagara during periods of high Ontario generation in the Niagara area, particularly during high demand period and during outage conditions. Under the conditions expected for this summer, studies show that the system is adequate to meet expected demands without this reinforcement.

The failed R76 voltage regulator and the BP76 circuit on the Niagara intertie will not be available for summer. A bypass will remain available for use, if required, until the R76 voltage regulator returns.

Phase angle regulators (PAR) are installed on the Ontario-Michigan interconnection at Lambton TS on the Ontario side and at Bunce Creek TS in Michigan, representing three of the four interconnections within Michigan. Final regulatory approvals have been received, permitting operation of these facilities. Two of three PARs began operation in April 2012 to help manage circulation power flows around Lake Erie, as well as contingencies. The operation of these PARs along with the PAR on the Ontario-Michigan interconnection (near Windsor) will control flows to a limited extent, and assist in the management of system congestion.

The necessary approvals for modifications to the existing Bruce Special Protection System (SPS) are in place to accommodate the full output of both new and existing generation in the Bruce area.

To prevent low voltage conditions on the 115 kV transmission system in the Woodstock area during summer extreme weather conditions, Hydro One is planning to add a new transformer station and a second supply point by extending the 230 kV transmission lines from Ingersoll to the Woodstock area and installing a new 230/115 kV transformer station. These plans will provide additional reliability if load growth continues in the area.

Operations

As part of the IESO-conducted analysis, an extreme weather scenario is used to assess the system under stressed conditions. An extreme weather scenario is generated by taking the most severe weather since 1970 on a week by week basis. This gives an "outer envelope" of the conditions that the system may face through the upcoming season. There are no new operating procedures resulting from integration of variable resources.

Additions of base load generation from nuclear and renewable sources combined with declining off-peak demands are expected to increase the frequency and magnitude of surplus generation events beginning in the spring of 2012 and persisting throughout the summer. The IESO does not anticipate any reliability concerns resulting from minimum demand and surplus generation.

A lack of direct control over a number of factors that contribute to surplus generation, such as weather, consumption and market behavior, poses operational challenges in managing surplus conditions. The need for maximum flexibility from all resources is integral to the efficient and reliable operation of the IESO grid.

With a forecasted increase in surplus generation, it is expected that some out of market control actions will be required to manage the surplus. These actions will extend beyond typical market actions, which include exports, minimum economic hydro dispatch and nuclear maneuvers. The IESO will continue to examine and pursue the ability to dispatch base load resources to manage these conditions. Finally, environmental and/or regulatory restrictions are not expected to impact reliability this summer

Vulnerability Assessment

Ontario generates its forecasts using median conditions for hydroelectric generation and does not expect any impacts from drought for summer 2012.

The IESO includes a quantity of demand response termed the “Reliably Available Capacity” in its reliability analysis. This does not represent the total registered capacity of demand response programs. For market-based programs, the IESO uses historical information to ascertain the amount of demand response capacity that is typically bid into the market at the time of the weekly peak demand. For programs that have contracts, the IESO uses both historical information and contract information in order to determine the quantity of Reliably Available Capacity.

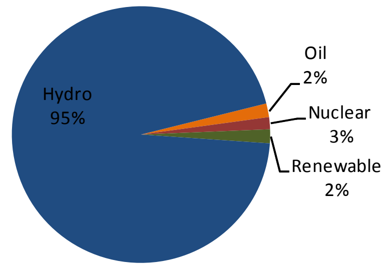
There are no significant planned long-term outage conditions expected over the summer season. Planned increases in variable generation do not present any resource adequacy or operational concerns over the summer season. Modifications to the existing Bruce special protection system are anticipated to accommodate new generation capacity from refurbishments at the relevant nuclear generating station and new wind power.

Generator owners and operators are required to keep sufficient supplies of fuel (*e.g.*, coal, nuclear fuel bundles, etc.). Coal inventories at the coal-fired plants are being carefully managed through 2014, when all coal generation has been legislated to be phased-out. There are communication protocols in effect between the IESO and gas pipeline operators to manage and share information under tight supply conditions in either sector (gas or electricity).

NPCC-Québec

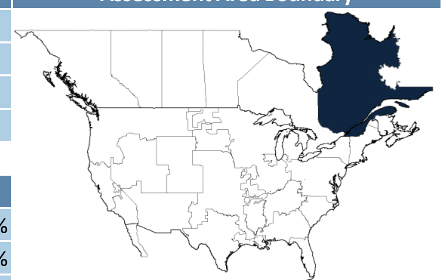
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	33,857	-
Future-Planned	50	-
Supply-Side Demand Response	0	-
Net Capacity Transactions	-1551	-
Anticipated	**32,356**	**54.16%**
Existing-Other and Future-Other	0	-
Prospective	**32,356**	**54.16%**
Reference Margin Level	-	**10.00%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**21,283**	**20,988**
Demand-Side Demand Response (2012)	-	0
Supply-Side Demand Response (2011)	0	-
Total Internal	**21,283**	**20,988**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	21,283	-1.39%
Actual Peak Demand	21,354	-1.71%
All-Time Summer Peak Demand (July 8, 2010)	22,092	-5.00%

Note: Additional information regarding the methods and assumptions used in the development of the NPCC- Québec seasonal assessment can be found in Appendix I and on the NERC website.[88]

Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the Québec Assessment Area. Data was collected from Hydro-Québec's three divisions responsible for resource and transmission adequacy. Projections are based on economic indicators, long-term weather forecasts, historic load data, generation and transmission data, as well as transactions with neighboring systems and areas.

The reserve margins for the Québec Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain well above the Reference Margin Level during the 2012 summer season. This is because the assessment area is winter-peaking and summer peak loads are typically about 58 percent of winter peak loads. Summer is therefore the preferred time for generator and transmission maintenance. Even with an appreciable amount of maintenance going on, the area still has enough margin to account for summer demand forecast uncertainty, Firm capacity transactions and other short term exports such as may be required by neighboring NPCC areas during their peak demand periods.

Capacity in the Area has actually gone down slightly from the last summer period. The Tracy oil-fired generation station (450 MW) has now been completely retired by Hydro-Québec Production (HQP) and minor hydro adjustments have also been made. On the other hand, 23 MW of small hydro are now in service along with four new wind generating stations (398 MW). Additionally, one wind G.S. (80 MW) is

[88] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

projected to be in service in June and one unit at La Sarcelle hydro G.S. (50 MW) will be placed online in July. Total Internal Capacity in August 2012 will be 42,888 MW.

According to Québec's demand forecast, Total Internal Demand has decreased slightly from 21,283 MW to 20,988 MW since the 2011 summer. This slight 1.4 percent decrease is mainly due to a slower anticipated economic growth than what was forecasted last year.

Planning Reserve Margins

The Québec Assessment Area (the Québec Area) is projecting a Planning Reserve Margin well above its target level during the 2012 Summer Operating Period.

Because the Québec Area is winter-peaking, the Reference Margin Level is calculated for winter periods and is evaluated at about 10 percent. Assumptions used to establish reserve margin criteria, target margin levels and resource adequacy levels, and results thereof, are discussed in the last 2011 Québec Area Comprehensive Review of Resource Adequacy (Approved by the Reliability Coordinating Committee of NPCC on November 29, 2011). The assessment can be found on the NPCC's website. For this summer assessment, the Reference Margin Level is set at 10 percent.

The Québec Area is projecting an adequate Planning Reserve Margin throughout the summer season. The all-time internal peak hourly demand is 37,717 MW set on January 24, 2011. A large amount of space heating load is present during Winter Operating Periods. Summer peak demands are of the order of 22,000 MW (about 58 percent of peak winter demand). Summer Operating Periods are usually characterized by extensive generator and transmission maintenance in preparation for the upcoming winter. This explains the high level of resource adequacy characteristic of summer periods in Québec.

Both Anticipated Reserve and Prospective Margins in the Québec Assessment Area are 54.16 percent for the 2012 summer. Because these Planning Reserve Margins are significantly above the Reference Margin Level, no particular issues or circumstances have been identified that would impact reliability during the 2012 summer. Table 58 includes the 2011 and 2012 reserve margins for the Québec Assessment Area.

Table 58: NPCC-Québec Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	10.00%	10.00%
Existing-Certain & Net Firm Transactions	40.89%	55.24%
Anticipated	42.28%	54.16%
Prospective	42.80%	54.16%

Demand

Table 59 compares 2011 and 2012 summer demand forecasts.

Table 59: NPCC-Québec Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	21,283	20,988	-295	-1.39%
Total Internal	21,283	20,988	-295	-1.39%

The 2012 summer demand forecast is slightly lower than the 2011 forecast (around 1.4 percent lower). This is mainly due to slower economic growth anticipated for 2012 (compared to the 2011 economic growth forecast).

The summer 2011 forecast was 21,283 MW, while the actual peak demand occurred on July 21, at 21,356 MW (due to above-normal temperatures). The difference between the August 2011 forecasted and the actual July 2011 summer peak is not significant (73 MW).

The methods used in the assessment demand forecast have not changed from previous year and there have been footprint changes or entity acquisitions or exits.

Demand-Side Management

Demand response programs are not required or available during summer operating periods in Québec. However, Energy Efficiency (EE) programs are implemented throughout the year and the total amount of EE associated with existing and projected programs is estimated to be equivalent to approximately 900 MW for the 2012 summer peak. EE programs and general energy saving trends are accounted for in the demand forecast.

Hydro-Québec Distribution (HQD) presents its EE plan update, titled: "Plan global en efficacité énergétique" to the Québec Energy Board (the regulatory body in Québec) for the upcoming years. This plan focuses on energy conservation measures and includes programs tailored to residential customers, commercial and institutional markets, small and medium industrial customers, and large-power customers. Examples of programs and tools for promoting energy savings for the residential customers include old refrigerator recycling, electronic thermostats, low-energy lighting, etc.[89] The provincial government, through its Ministry of Natural Resources, also implements EE programs.

Generation

Approximately 97 percent of the Existing-Certain capacity is made up of hydroelectric resources, with the remaining 3 percent consisting of nuclear, gas-fired turbines and biomass generation. Thermal generation totals 1,898 MW of which 675 MW is nuclear generation, 507 MW is combined-cycle natural gas generation (mothballed for 2012), and 716 MW is gas-fired generation (280 MW from La Citière G.S. are also mothballed).

The only variable resources currently integrated in the Québec Assessment Area is wind. Nameplate capacity is now evaluated at 1,057 MW and continued growth is expected. On-peak wind capacity is entirely derated throughout the 2012 summer.

The amount of Existing-Certain, Existing-Other and Future-Planned and Future-Other capacity resources in service or expected to be in service are provided in Table 60.The Future-Planned line represents the coming on-line of 50 MW from La Sarcelle hydroelectric generating station unit on the James Bay system in July. Previously, in June, 80 MW of wind power generation will have been brought into service.

[89] Program characteristics can be found on Hydro-Québec's website: http://www.hydroquebec.com/energywise/index.html.

Table 60: NPCC-Québec Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	31,396	33,857
Future-Planned	768	50
Supply-Side Demand Response	0	0
Net Capacity Transactions	-1,411	-1,551
Anticipated	**30,753**	**32,356**
Existing-Other and Future-Other	1,312	0
Prospective	**32,065**	**32,356**

When compared to NERC's *2011 Summer Reliability Assessment*, some resources changes have occurred for the 2012 summer period. The Tracy oil-fired generation station (450 MW) has now been retired by HQP. 23 MW of small hydro plants that are under contract with HQD are now in-service and other minor hydro adjustments have been made. Accordingly, no fuel issues or other conditions that would result in capacity reductions are expected for the 2012 summer period.

The Québec Assessment Area's renewable resource portfolio includes hydro, wind and biomass (by order of total capacity). There are no solar resources in the Québec Assessment Area.

Biomass and wind resources are owned by Independent Power Producers (IPPs). These IPPs have signed contractual agreements with Hydro-Québec. For biomass, maximum capacity and expected on-peak capacity are equal to contractual values. Wind resources maximum capacity is also equal to contractual capacity. Since the Québec Assessment Area is winter-peaking, HQD has evaluated wind resource expected capacity for the winter operating season only. The summer wind capacity expected on-peak entirely derated during the 2012 summer operating period. Figure 41 and Table 61 present the renewable resource portfolio for the 2011 and 2012 summer peaks in the Québec Assessment Area.

Figure 41: NPCC-Québec Renewable Resources

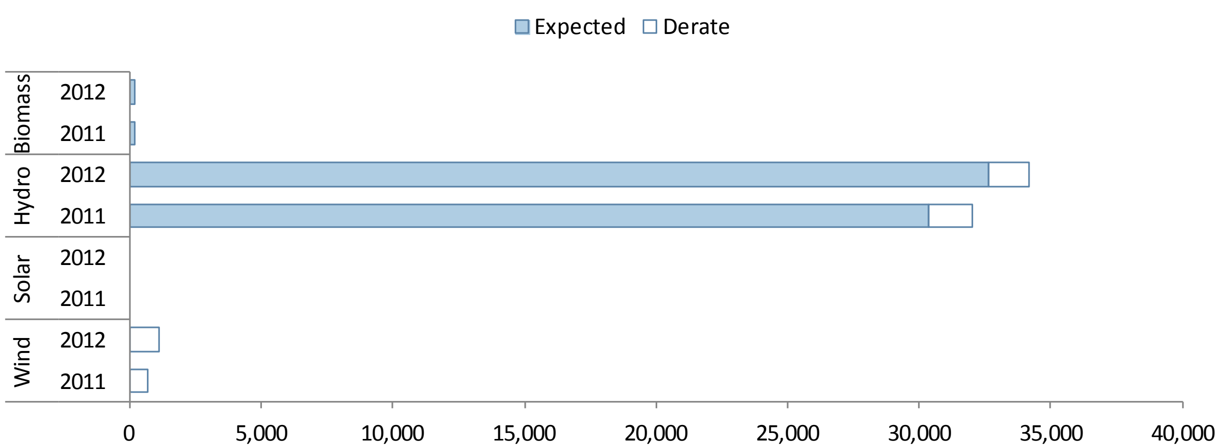


Table 61: NPCC-Québec Renewable Resources

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	0	0	0	0	30,366	32,628	164	175
Derate	659	1,137	0	0	1,642	1,565	0	0
Nameplate	**659**	**1,137**	**0**	**0**	**32,008**	**34,193**	**164**	**175**

Capacity Transactions

The Québec Area has not forecasted any imports during the 2012 summer and does not rely on any emergency imports to meet its Reference Margin Level. However, projected exports to neighboring areas total 1,551 MW, of which 1,275 MW are Firm, with the remaining 276 MW categorized as Expected. The breakdown is as shown and in Table 62:

- 896 MW to New York (620 MW are considered Firm)
- 510 MW to New England
- 145 MW to Ontario (Cornwall)

Table 62: NPCC-Québec Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	0	1,275	-1,275
Expected	0	276	-276
Total	**0**	**1,551**	**-1,551**

Under emergency conditions, especially during the winter, the Québec Assessment Area can rely on imports from Ontario (IESO), New York (NYISO), and the Maritimes Assessment Area. Capabilities vary with system conditions. TransÉnergie, the Transmission Operator, has agreements with all neighboring NPCC subregions that detail conditions and procedures for exchanging emergency energy. A procedure supervises Control Centre actions and communications for this energy exchange. Overall, no reliability concerns have been identified in the Québec Assessment Area for the 2012 summer.

Transmission

Transmission project commissioning is usually scheduled during fall, in preparation for the upcoming winter peak period. No specific projects are needed to maintain or enhance reliability during the 2012 summer. As a corollary, no project delays or temporary service outages for transmission facilities are expected that would impact reliability during the 2012 summer.

A majority of the maintenance on transmission lines, transformers and generating units is performed during the summer period. Resource availability is not a problem during summer, even though exports to summer peaking NPCC subregions are sustained during peak hours. Available resources for exports actually often exceed actual summer transfer capabilities to neighboring NPCC systems.

The following three major transmission projects (originally mentioned in the NERC *2011/2012 Winter Reliability*) have been commissioned and placed in-service since prior to the 2012 summer: two -300/+300 Mvar Static Var Compensators (SVCs) at the Chénier 735/315 kV substation; a 735-kV series compensation project at Jacques-Cartier substation (on two lines near Québec City); and a 345-Mvar, 315-kV shunt capacitor bank in the Montréal area.

Operations

TransÉnergie's significant operating studies are typically performed for the winter season, where weather conditions contribute to higher demand levels. Readers may refer to the earlier seasonal assessments for details.[90]

[90] http://www.nerc.com/page.php?cid=4|61.

Hydro-Québec participates in NPCC's seasonal CO-12 (Operations Planning) and CP-8 (Multi-Area Probabilistic Assessment) Working Group assessments of system reliability.[91] All operational planning studies are done in compliance with NPCC and NERC planning standards. These include planning studies for the bulk power system, generation integration studies, NPCC reviews, transfer limit studies, etc. The latest NPCC Comprehensive Review of the Québec transmission system for 2011-2012 was completed in May 2008. The last Interim Review of the Québec transmission system for 2016 was completed in November 2011. No particular operational problems have been observed for the oncoming 2012 summer operating period.

Currently, wind generation variability has not significantly impacted the system's day-to-day operation and the present level of wind generation does not necessitate particular operating procedures. However, data acquisition for different wind generation variables constitute valuable information for system management and wind generation forecasting is used in the subregion's system forecasting software. Long-term foreseeable impacts on system management will be addressed as necessary:

- Wind generation variability on system load and interconnection ramping.
- Frequency and voltage regulation problems.
- Increase of start-ups and/or shutdowns of hydro units due to load following coupled with wind variability. Generally units must be operated within certain limits to ensure efficiency.
- Reduction of low load operation flexibility due to low inertial response of wind generation coupled to must-run hydro generation.

No reliability concerns resulting from minimum demand and over generation are anticipated. There is hydroelectric must-run generation on run-of-the-river installations but this is small relative to system size. Moreover, as mentioned before, most generator maintenance is done during the summer, while reservoirs are allowed to fill up. A relatively high export level is usually maintained to neighboring summer peaking areas. No other unusual operating conditions are anticipated for the upcoming summer.

Vulnerability Assessment

Given the importance of hydroelectric resources, the Québec Area has developed an energy criterion to assess its energy reliability, stating that sufficient resources should be available to go through sequences of two or four consecutive years of low water inflows totaling 64 TWh and 98 TWh, respectively, and having a 2 percent probability of occurrence. These assessments are presented three times a year to the Québec Energy Board. Normal hydro conditions are projected for 2012 summer and reservoir levels are sufficient to meet both peak demand and daily energy demand throughout the summer.

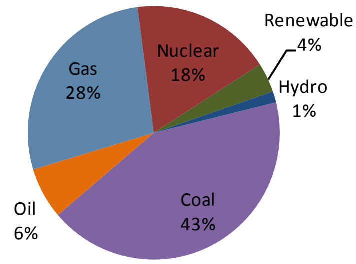
There are no significant long-term generator outages for this assessment period nor any pending future environmental regulations that may have an impact in the Québec Area for the upcoming season.

[91] https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx.

PJM

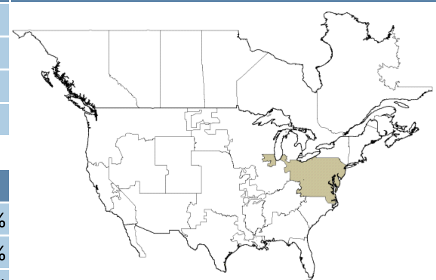
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	185,424	-
Future-Planned	0	-
Supply-Side Demand Response	0	-
Net Capacity Transactions	217	-
Anticipated	**185,641**	**30.61%**
Existing-Other and Future-Other	0	-
Prospective	**190,471**	**34.01%**
Reference Margin Level	-	**15.60%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**137,341**	**142,135**
Demand-Side Demand Response (2012)	-	11,647
Supply-Side Demand Response (2011)	11,600	-
Total Internal	**148,941**	**153,782**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	137,341	3.49%
Actual Peak Demand	158,043	-10.07%
All-Time Summer Peak Demand (July 21, 2011)	158,043	-10.07%

Note: Additional information regarding the methods and assumptions used in the development of the PJM seasonal assessment can be found in Appendix I and on the NERC website.[92]

Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the PJM RTO Assessment Area. Data is based on economic indicators, long-term weather forecasts, and historic load data.

This year's report includes the load and resources of Duke Energy Ohio/Kentucky (DEOK), which was integrated into the PJM RTO on January 1, 2012.

The reserve margins for the PJM RTO Assessment Area are based on Anticipated resources. The Anticipated Reserve Margin will remain above the PJM Reference Margin Level during 2012 summer.

A total of 5,007 MW of capacity have been added since the 2011 summer. According to the PJM's demand forecast, Total Internal Demand has decreased from 154,383 MW[93] to 153,782 MW since the 2011 summer. This equates to an annual growth rate of -0.4 percent.

Planning Reserve Margins

PJM is projecting an adequate reserve margin for the 2012 summer peak of 30.6 percent. The reserve margin calculation includes forecasted load, Existing-Certain generating resources, forecasted Demand-Side Management (economic DSM treated as a resource and emergency DSM treated as a load reducer), net transfers and Energy Efficiency treated as a resource. The PJM RTO Reserve Requirement is 15.6

[92] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

[93] Adjusted for the integration of Duke Energy/Kentucky (DEOK). The forecast in the *2011 Summer Reliability Assessment* was 148,941 MW.

percent for the 2012 and 2013 planning period.[94,95] Table 63 includes the 2011 and 2012 reserve margins for the PJM Assessment Area.

Table 63: PJM Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	15.00%	15.60%
Existing-Certain & Net Firm Transactions	29.76%	30.61%
Anticipated	29.76%	30.61%
Prospective	29.76%	34.01%

The Reliability Pricing Model (RPM) or Forward Capacity Market provides:

- Procurement of capacity through a competitive auction three years before it is needed;
- Locational pricing for capacity that reflects limitations on the transmission system's ability to deliver electricity into an area and determine capacity needs throughout PJM;
- A variable resource requirement to help set the price for capacity;
- A backstop mechanism to ensure the availability of sufficient resources to preserve system reliability.

PJM will have an adequate reserve margin throughout the 2012 summer. The difference between the PJM RTO reserve margin and the PJM RTO Reference Margin is 15.6 percent (amounting to over 21,000 MW). The highly unlikely loss of this amount of generation due to retirements or forced outages would task the PJM operators to find replacement resources. An extremely hot and humid summer could push load up but the probability of this occurring has been included in PJM's Reserve Requirement studies.

Demand

The PJM RTO 2011 summer peak was 163,762 MW, which occurred on July 21, 2011. This was the PJM RTO's All-Time Peak. On a weather-normalized basis, the PJM RTO 2011 summer peak was 154,383 MW.[96] The difference can be attributed to a very hot summer in most of the PJM Region. Several consecutive days were above 100 degrees, which is unusual for the PJM Region.

Table 64 includes the 2011 and 2012 summer demand forecasts for the PJM Assessment Area. The forecast for the 2012 summer peak is 153,782 MW. The combination of new economic drivers and a downward revision to the economic outlook has resulted in lower peak and energy forecasts for PJM compared to the same year in last year's report. This year's forecast reflects PJM's adoption of an independent consultant's recommendation to replace the load model's previous economic driver (Gross Metropolitan Product) with a variable that incorporates six economic measures (Gross Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment).

The forecasted demand for 2012 includes the load of Duke Energy Ohio/Kentucky (DEOK), which was integrated into the PJM RTO on January 1, 2012.

[94] Runs from June 1, 2012 through May 31, 2013.

[95] For additional information, see the 2011 PJM Reserve Requirement Study: http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/2011-rrs-study.ashx.

[96] Adjusted for the integration of Duke Energy/Kentucky (DEOK). The forecast in the 2011 Summer Reliability Assessment was 148,941 MW.

Table 64: PJM Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	**137,341**	**142,135**	**4,794**	**3.49%**
Total Internal	**148,941**	**153,782**	**4,841**	**3.25%**

A downward revision to the near-term economic outlook for both the U.S. and PJM has resulted in lower peak demand and energy projections in the 2012 load forecast, compared to the 2011 load forecast. This is tied to revised assumptions regarding the timing of the U.S. economic recovery. While growth in later years accelerates, the short-term, seasonal economic outlook is unable to make up the difference between the 2011 and 2012 forecasts until after 2022.

Demand-Side Management

Acceptance of Demand-Side Management (DSM) resources for the 2012 summer peak period will continue through the end of May 2012. Approximately 4,000 MW has been accepted already and this value continues to grow on a daily basis. Over 11,600 MW of Demand-Side resources were available in PJM during the 2011 summer peak period and similar amounts are projected for the 2012 summer. 2011 actual DSM has been incorporated into this summer's forecast. A total of 581 MW of Energy Efficiency is expected to be available during the 2012 summer peak. Figure 42 and Table 65 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the PJM Assessment Area.

Figure 42: PJM Demand Response

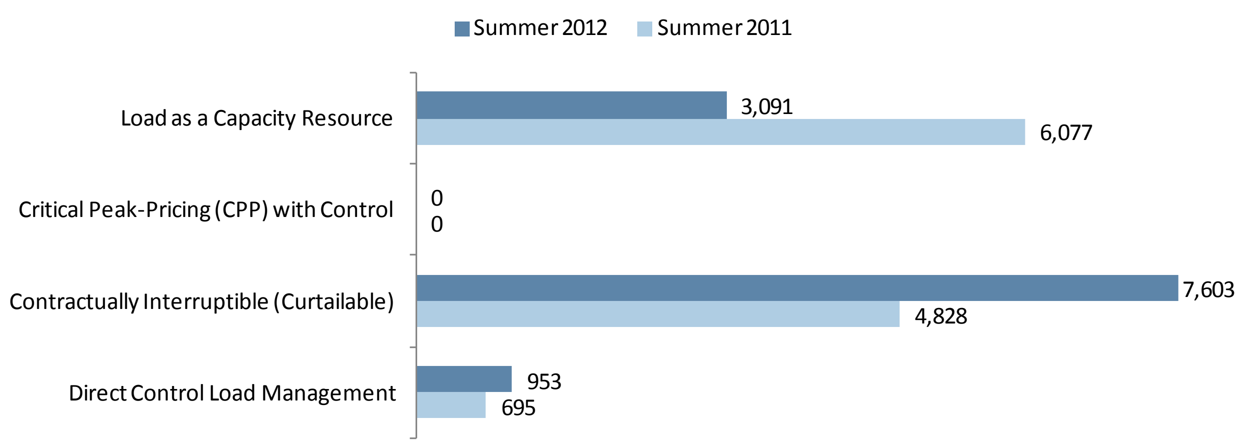


Table 65: PJM Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	695	7,603	0
Contractually Interruptible (Curtailable)	4,828	953	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	6,077	3,091	0
Total Demand Response	**11,600**	**11,647**	**0**
Percentage of Total Internal Demand	**7.79%**	**7.57%**	**0.00%**

DSM resources are offered as dispatchable resources, committed resources, or energy products in PJM. Demand response accepted in the Reliability Pricing Model (RPM) Forward Capacity Market is committed and dispatchable, similar to a generator. This DSM is able to be retained for use by PJM operators during capacity emergencies. Energy DSM can be applied as reserves, accepted through the ancillary service market. DSM used for reserves is limited by the RFC standard BAL-002-RFC-02[97] to 25 percent of the operating reserve requirement. This type of DSM is usually fully subscribed and can range up to approximately 2,500 MW during a peak summer day. Economic DSM can also be called for emergency conditions, but is not obligated to perform.

Energy Efficiency programs included in the 2012 load forecast are impacts approved for use in the PJM Reliability Pricing Model (RPM). Measurement and verification (M&V) of Energy Efficiency programs are governed by rules specified in PJM Manual 18B. To ensure the value of an Energy Efficiency resource, providers must comply with the measurement and verification standards, defined in this manual by establishing M&V plans, providing post-installation M&V reports, and undergoing an M&V audit.

Generation

The primary source of fuel in PJM is coal, at approximately 42 percent (77,000 MW), followed by natural gas at approximately 26 percent (48,000 MW) and nuclear at approximately 18 percent (33,600 MW). No capacity resource changes are expected though the summer of 2012. Acceptance of modifications to capacity categorized as Existing-Certain occur once per year on June 1. Table 66 includes projections of PJM RTO resources for the 2011 and 2012 summer.

Table 66: PJM Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	180,406	185,424
Future-Planned	0	0
Supply-Side Demand Response	11,600	0
Net Capacity Transactions	1,260	217
Anticipated	**193,266**	**185,641**
Existing-Other and Future-Other	0	0
Prospective	**193,266**	**190,471**

PJM had an increase of 5,007 MW of Existing-Certain capacity since last summer, almost completely due to the integration of DEOK generation. Capacity additions and retirements in the rest of PJM almost netted-out and are listed below:

- A new natural gas combined-cycle 545 MW unit was added by American Electric Power (AEP) at Dresden.
- Two Kearny natural gas units (13 and 14) added 267 MW to the Public Service Electric and Gas Company (PSE&G) generation portfolio.
- A 585 MW natural gas combined-cycle unit named Virginia City was added in AEP.
- The Martins Creek 4 oil unit was uprated by 70 MW in PPL.
- Two Susquehanna nuclear units (1 and 2) in PPL were uprated 90 MW.
- A net of 568 MW of uprates and derates also occurred.

[97] https://www.rfirst.org/standards/Documents/BAL-002-RFC-02.pdf.

- Benning 15 and 16 totaling 548 MW of oil generation were retired in Baltimore Gas and Electric (BGE).
- Gorsuch units 1-4, totaling 189 MW of coal generation, were retired in AEP. The Buzzard Point East and West oil combined-cycle combustion turbines, totaling 210 MW were retired in Pepco.
- The Hudson 1 natural gas unit at 322 MW was retired in PSE&G.
- In PSE&G the Kearny 10 and 11 natural gas units were retired for a loss of 250 MW.
- The State Line 3 and 4 units were totaling 515 MW retired from ComEd.
- No units were brought back into service since the last summer assessment.

PJM has no ongoing long-term outages of generation. Behind-the-meter generation is not considered in capacity calculations but rather offsets load that is also behind-the-meter.

The Laurel Mountain Energy Storage Facility consists of eight "Smart Grid Stabilization System" lithium ion battery modules for a total output of 27.4 MW on the same site as the Laurel Mountain Wind Farm in West Virginia. Two MW (300 kilowatt hours of storage) batteries for frequency regulation have been installed on the same property as the Paradise Solar project in Deptford, New Jersey. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 43 and Table 67.

Figure 43: PJM Renewable Generation

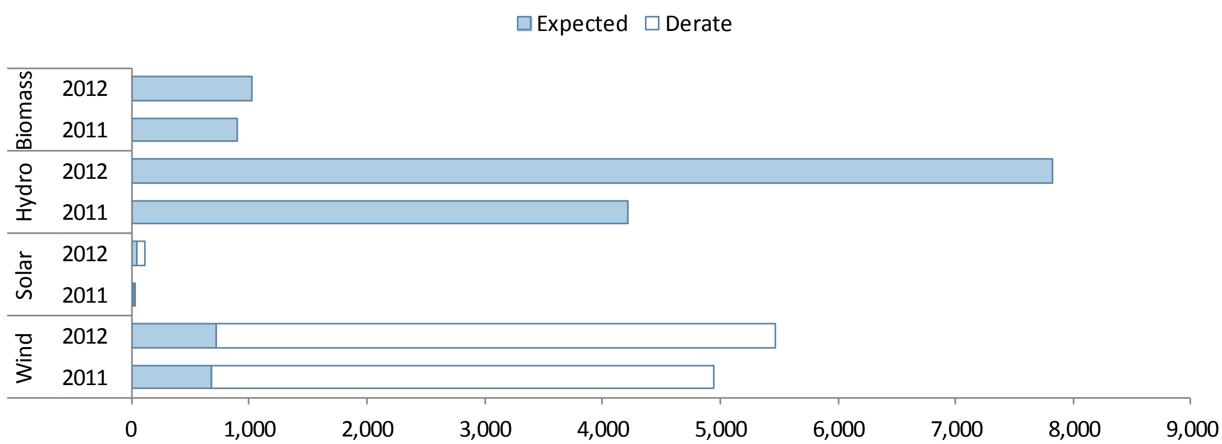


Table 67: PJM Renewable Generation

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	670	711	12	42	4,212	7,822	896	1,023
Derate	4,272	4,761	20	69	0	0	0	0
Nameplate	**4,942**	**5,472**	**32**	**111**	**4,212**	**7,822**	**896**	**1,023**

Capacity Transactions

All transactions are considered Firm throughout the summer for both specific generation and transmission. Firm contracts are mostly long-term but some are shorter (ranging from one to three years). PJM has no reliance on outside assistance for emergency imports. The availability of emergency generation is not needed for PJM to meet the Reference Margin Level. On-peak capacity transactions projected for the 2012 summer are included in Table 68.

Table 68: PJM Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	1,453	1,236	217
Expected	0	0	0
Total	**1,453**	**1,236**	**217**

Transmission

Since the beginning of the last winter peak season, the following facilities have come online:

- Chase City-Clarksville 115 kV line in Dominion
- Brookside-Reedsburg-Longview 138 kV line in ATSI

It is anticipated that the following facilities will go in service prior to the 2012 summer:

- Fredricksburg-Possum Point 230 kV line will get tapped to Garrisonville in Dominion
- Remington-Sowego will be converted from 115 kV to 230 kV in Dominion
- A second Dooms-Dupont-Waynesboro 115 kV line in Dominion
- Yorktown-Hayes 230 kV in Dominion
- Indian River-Bishop 138 kV line in Delmarva

It is anticipated that the following facilities will go in service during the 2012 summer:

- A second Whiteley-Franklin 138 kV line will be added in AP
- The Galion-GM Mansfield-Longview 138 kV line will be reconfigured to bypass GM Mansfield in ATSI
- Two Perryman-Harford 115 kV lines in BG&E
- Hopewell-Bull Hill 230 kV line in Dominion
- Two new Ritchie-Benning Station ""A"" 230 kV lines in Pepco

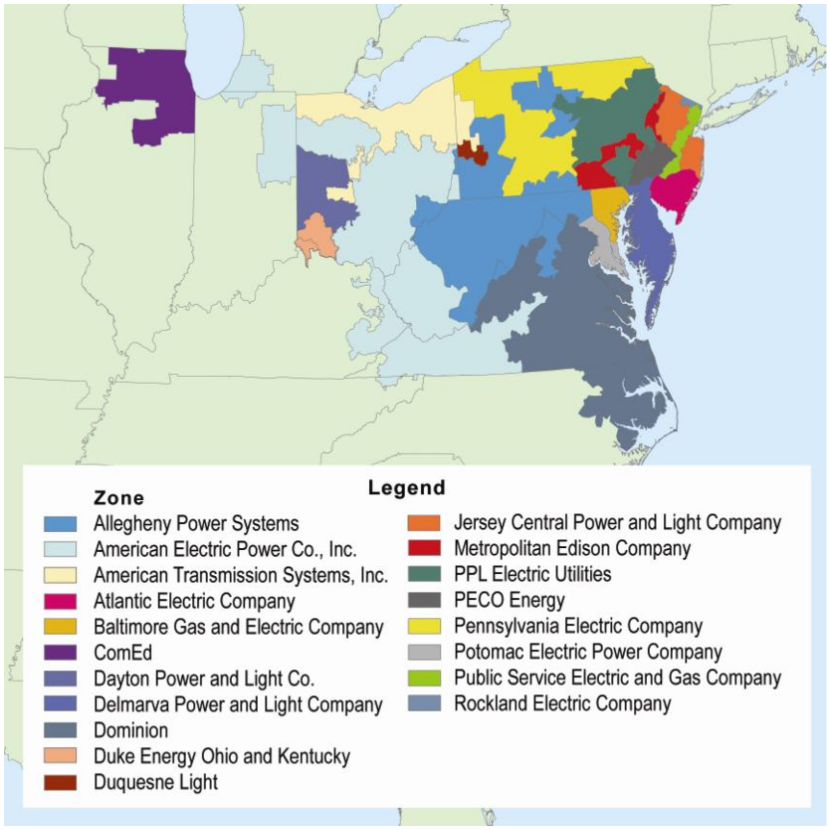
- The Linden 230 kV PAR was replaced.

No other substation equipment is expected to be added and no project delays or temporary service outages for transmission facilities (lines or transformers) are expected to impact reliability during this summer. No new transmission projects are required in order to maintain reliability.

Operations

The PJM Operations Analysis Task Force (OATF) summer assessment did not identify any reliability issues. The OATF does anticipate redispatch and switching procedures to control local thermal and voltage violations in some transmission zones. See Figure 44.

Figure 44: PJM Transmission Zones



No special operating procedures are required from the integration of variable resources. PJM has developed a Wind Power Forecast tool and visualization to assist operations. PJM has integrated wind into its automated dispatch systems. PJM does not anticipate any reliability concerns resulting from minimum demand or over generation. Intermittent resources can be required to disconnect. Established procedures ensure reliability concerns resulting from over-generation are addressed.[98]

There are some minor concerns related to the amount of information available to PJM that can be used to determine the amount of demand response to dispatch during emergency conditions. PJM has filed tariff changes with FERC that will require more robust reporting of the demand response operational capability in real-time for Curtailment Service Providers. While this is not considered a reliability concern for PJM, the additional information will help avoid the dispatch of demand response that may not be necessary to meet the need during emergency conditions. PJM has addressed the issue of availability by creating 3 different DR products: Limited DR (10 days for 6 hours per day), Extended Summer DR (unlimited days during a defined summer period for 10 hours per day) and Annual DR (unlimited days for 10 hours per day of a given year). Capacity resources (and DR treated as capacity) in PJM are required to meet PJM's reliability requirements.

PJM requires generation owners to place resources into the "Maximum Emergency Category" if environmental restrictions limit run hours pre-determined levels. Max Emergency units are the last to be dispatched.

[98] http://www.pjm.com/~/media/documents/manuals/m12.ashx.

Vulnerability Assessment

PJM has very little hydro generation and reservoir levels are expected to be adequate throughout the 2012 summer. PJM expects no problems with warm cooling water. Any one specific generator outage, even if it is long-term, can be replaced with other resources available within PJM. Demand-side resources do not contribute enough to the resource mix to be of great concern for unresponsiveness. Penalties exist for Firm demand-side resources to make unresponsiveness financially unattractive. No special operating procedures are required. PJM has developed a Wind Power Forecast tool and visualization to assist operations.

The Richland 138 kV substation in FirstEnergy (ATSI) will be reconfigured to permit the removal of the Richland SPS in June of 2012. No new Special Protection Schemes (SPS) have been added in PJM since the prior summer.

PJM is assessing the impacts of the CSAPR (Cross State Pollution Rule), MATS (Mercury Air and Toxics Standards) and also state level environmental rules like NJ HEDD (High Electricity Demand Day) on resource adequacy, transmission planning and ancillary services for the PJM footprint. PJM developed an analysis of coal generation at risk of retiring based on an assessment of required environmental retrofit costs vs. the cost of constructing a new natural gas-fired turbine. This at risk generation analysis concluded that there is no overall resource adequacy concern for the PJM footprint, however there may be localized reliability concerns that will need to be addressed either with replacement generation capacity or transmission upgrades if the impacted units are retired or need lengthy environmental retrofit outages. PJM continues to coordinate closely with PJM Generation Owners, PJM Transmission Owners and neighboring systems through the PJM Committee structure and consistent with the PJM Tariff and manuals. In order to maintain system reliability, PJM will designate units as "Reliability Must Run" if their retirement date is targeted to be in advance of required system reinforcements.

PJM requested that all impacted generation owners provide the most accurate information regarding unit retirements, environmental retrofits, unit derates, and potential regulatory issues related to the environmental regulations. Combined with the publically announced unit retirements and the deactivation analysis results, PJM is utilizing this information to address short term impacts and long-term projections through 2018. PJM is communicating with interconnected Transmission Owners as required to address local reliability issues, and also communicating with MISO to compare reliability analyses and coordinate outages.

At this point PJM has added the environmental retrofit outages, to the extent provided by the generation owners, to projections for maintenance outages from 2012-2018, and is continuing to assess the impact to off-peak reliability. PJM will continue to coordinate closely to analyze the impact of retiring generation, planned outage to perform retrofits, normal generation and transmission maintenance outages as well as transmission outages required to perform planning upgrades resulting from retiring generation.

Generation owners have indicated that while at this time there appears to be sufficient time to complete environmental retrofits, if there are delays in scheduling retrofit outages due to system constraint issues or capital budget limitations, then there may be significant challenges in completing the retrofit outages in the required time to comply with environmental regulations.

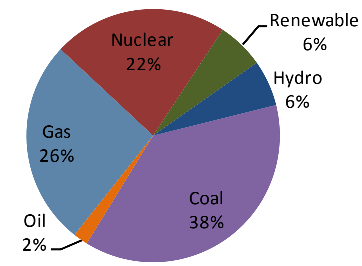
Generators owners are expected to begin environmental retrofit work during the spring 2012 maintenance period.

PJM has established rules/procedures to ensure fuel is conserved to maintain an adequate level on-site fuel supplies under forecasted peak load conditions. PJM coordinates with neighboring entities and gas pipelines to quickly address fuel issues. No fuel supply issues are anticipated. No fuel transportation issues are anticipated.

SERC-E

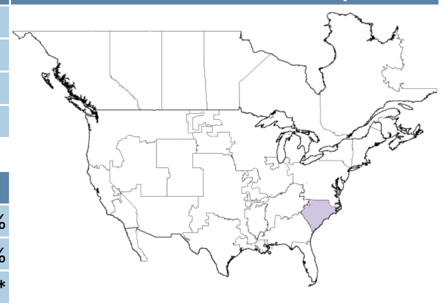
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	49,768	-
Future-Planned	635	-
Supply-Side Demand Response	1,687	-
Net Capacity Transactions	1586	-
Anticipated	**53,676**	**22.52%**
Existing-Other and Future-Other	0	-
Prospective	**53,676**	**22.52%**
Reference Margin Level	-	**15.00%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**41,562**	**41,378**
Demand-Side Demand Response (2012)	-	1,878
Supply-Side Demand Response (2011)	1,687	-
Total Internal	**43,249**	**43,255**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	41,562	-0.44%
Actual Peak Demand	43,253	-4.34%
All-Time Summer Peak Demand	N/A*	N/A*

*Boundary changes applied in 2011.

Note: Additional information regarding the methods and assumptions used in the development of the SERC-E seasonal assessment can be found in Appendix I and on the NERC website.[99]

Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the SERC-E Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The reserve margins for the SERC-E Assessment Area are based on Anticipated or Prospective resources. Both the Anticipated Reserve Margin will remain above the Reference Margin Level during the 2012 summer season.

A total of 825 MW of capacity additions will be added during the 2012 summer. According to the SERC-E Assessment Area demand forecast, Total Internal Demand has increased slightly from 43,249 MW to 43,255 MW since the 2011 summer. This equates to an annual growth rate of 0.02 percent.

No reliability concerns in meeting in service dates are expected to significantly impact reliability in the SERC-E Assessment Area.

Planning Reserve Margins

Reserves are projected to provide an adequate and reliable power supply during the 2012 summer. Generation resources are planned to ensure that reserve margins are met and resource plans are reviewed and revised as needed to achieve these Planning Reserve Margins.

[99] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

In SERC-E, utilities do not adhere to a regional/Assessment Area target or other criteria. Therefore, NERC assigns a default 15 percent Reference Margin Level. However, renewable resources are included in North Carolina utility portfolios to meet the requirements of the state's Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Under this standard, investor-owned utilities in North Carolina will be required to meet up to 12.5 percent of their energy needs through renewable energy resources or Energy-Efficiency measures. Rural electric cooperatives and municipal electric suppliers are subject to a 10 percent REPS requirement.[100] Variable resources are assessed for their availability to meet the needs of customers' reliably and economically, based on the requirements of the standard and maintaining flexibility in making long-term resource decisions. The Anticipated Reserve Margin for the 2012 summer is 22.52 percent. Table 69 includes the 2011 and 2012 reserve margins for the SERC-E Assessment Area.

Table 69: SERC-E Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	**15.00%**	**15.00%**
Existing-Certain & Net Firm Transactions	**22.64%**	**22.52%**
Anticipated	**24.11%**	**22.52%**
Prospective	**24.11%**	**22.52%**

No operational problems are anticipated that would detract from the projections in this assessment. For the forecast and any extreme peaks, reserve margins are such that the loss of multiple units can be managed without threatening reliability. The VACAR reserve sharing agreement (RGA) is also available to support recovery from such extreme events. Beyond these measures, transmission reserve margins can also be used to secure market purchases to maintain reliability. As stated in annual integrated resource plan filings with the North Carolina Utilities Commission (NCUC), various entities are evaluating a wide range of factors in order to ensure reliable and cost effective service to customers. Over the next 10 years, entities will be evaluating numerous factors including potential impacts from environmental regulations and rules, integration of renewable energy, new generation technologies and rising commodity costs. These issues will be addressed in future long-term assessments.

Demand

Slight changes from the 2011 summer actual (43,253 MW) and peak demand forecast (43,249 MW) are primarily due to changes in interruptible demand, class sales mix and load factors used to develop the peak demand forecast. The 2012 summer peak demand forecast is projected to be 43,255 MW. Some entities within the Assessment Area are currently reevaluating forecasting models for the most recent regional and local economic projections.[101] Projections in this Assessment Area are expected to be normal; however, energy sales projections that serve as a primary driver of the load forecast for certain entities are lower based on revised economic growth assumptions. No other significant changes or enhancements were reported for this year's forecasting methods. Table 70 includes the demand forecasts for the 2011 and 2012 summers for the SERC-E Assessment Area.

[100] http://www.ncuc.commerce.state.nc.us/reps/reps.htm.

[101] This information will come from vendors such as Economy.com and IHS Global Insight. Weather projections were taken from various sources such as the National Oceanic and Atmospheric Administration (NOAA) or individual company databases.

Table 70: SERC-E Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	**41,562**	**41,378**	**-184**	**-0.44%**
Total Internal	**43,249**	**43,255**	**6**	**0.01%**

Demand-Side Management

Demand Response and Energy Efficiency programs are projected to be 1,878 MW and 223 MW, respectively. These programs are used to reduce the affects of summer peaks and are considered part of the utilities' resource planning. Demand Response is projected to be 4.34 percent of Total Internal Demand, representing a 0.9 percentage point increase from 2011 projections. This increase is projected to reduce peak demand on entity systems within the Assessment Area. Figure 45 and Table 71 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the SERC-E Assessment Area.

Figure 45: SERC-E Demand Response

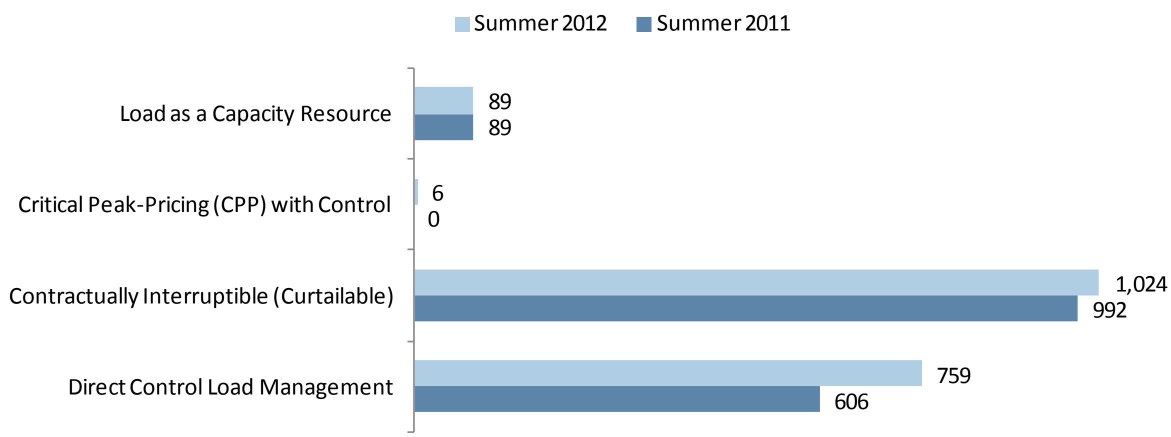


Table 71: SERC-E Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	606	759	0
Contractually Interruptible (Curtailable)	992	1,024	0
Critical Peak-Pricing (CPP) with Control	0	6	0
Load as a Capacity Resource	89	89	0
Total Demand Response	**1,687**	**1,878**	**0**
Percentage of Total Internal Demand	**3.90%**	**4.34%**	**0.00%**

A few entities are still assessing the effects of newly approved Energy Efficiency programs installed on the system in 2010. However, a variety of existing programs that support Energy Efficiency and Demand Response are offered to customers in SERC-N. Some of the programs are current Energy Efficiency and Demand-Side Management (DSM) programs that include: interruptible capacity, load control curtailing programs, residential air conditioning direct loads, energy products loan programs, standby generator controls, residential time-of-use, Demand Response programs (interruptible and related rate structures), Power Manager Power Share conservation programs, residential Energy Star rates, Good Cents new home program, commercial Good Cents program, thermal storage cooling program, H20 Advantage water heater program, general service and industrial time-of-use, and hourly pricing for incremental load interruptible. The commitments to these programs are part of a long-term, balanced energy strategy to meet future energy needs. Load response will be measured by trending real-time load data from telemetry and statistical models that identify the difference between the actual consumption and the projected consumption absent the curtailment event.

Generation

Companies within the SERC-E Assessment Area expect to have 50,008 MW of Existing-Certain, 0 MW of Existing-Other, 64 MW of Existing-Inoperable capacity. This capacity is projected to help meet demand during this time period. Coal is the primary source of fuel within this area, representing 37.8 percent of Existing-Certain Resources. Approximately 25 MW of Existing-Certain resources have been added since the prior season. This amount includes 5 MW of solar and 20 MW of biomass. Additionally, 1,470 MW of Future-Planned resources are projected to be added leading up to and during the period. Entities have reported 656 MW of unit retirements prior to the months of June through September, and 382 MW of unit retirements during the month of September. However, new generation came online in late 2011, with more expected in mid-2012. Additional units have not been identified for retirement at this time. Internal company discussions of these options have included mitigation measures that must be explored and considered as part of any decision to retire existing generating units. Table 72 includes projections of SERC-E resources for the 2011 and 2012 summer.

Table 72: SERC-E Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	49,768	49,728
Future-Planned	635	0
Supply-Side Demand Response	1,687	0
Net Capacity Transactions	1,586	968
Anticipated	**53,676**	**50,696**
Existing-Other and Future-Other	0	0
Prospective	**53,676**	**50,696**

Approximately 25 MW of new generation has been added to the area since the last summer season. There are no new generator uprates in service or out of service generation during the period.[102] 994 MW will be brought back into service for the period. No behind-the-meter generation was reported and no extended outages are expected during this summer. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 46 and Table 73.

[102] SERC methods of data collection do not identify specific uprates or derates throughout the year. Rather, entities reporting to SERC make changes to unit generation continuously throughout the year.

Figure 46: SERC-E Renewable Generation

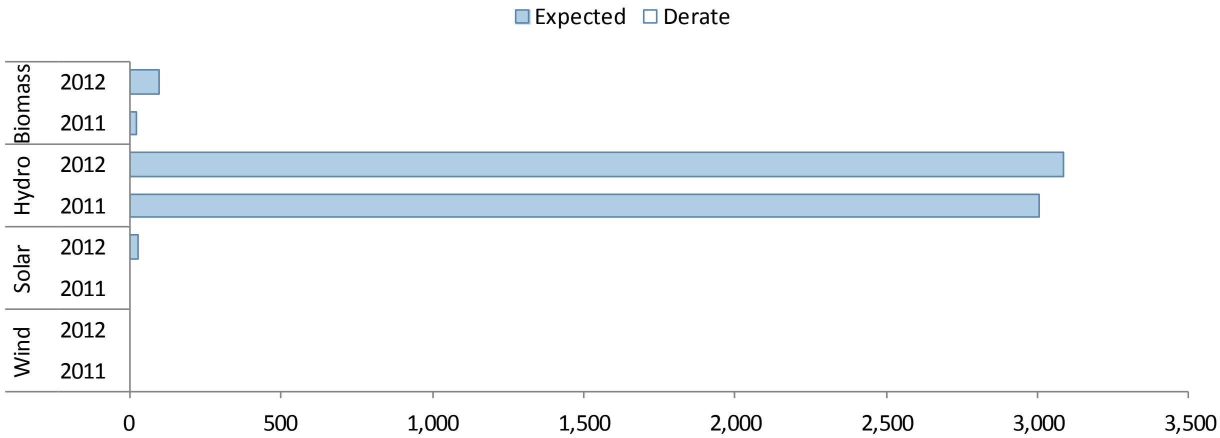


Table 73: SERC-E Renewable Generation

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	0	0	0	28	3,006	3,087	21	97
Derate	0	0	0	0	0	0	0	0
Nameplate	**0**	**0**	**0**	**28**	**3,006**	**3,087**	**21**	**97**

Variable resources are limited within SERC-E and are assessed for availability to meet the needs of customers reliably and economically, based on the requirements of the regulatory standards and ability to maintain flexibility for long-term resource decisions. As required, entities will continue to evaluate these and other renewable resources as part of their integrated resource planning process. In addition, no immediate changes in entity planning procedures are needed due to small increments of variable resources.

Capacity Transactions

Utilities within the SERC-N Assessment Area expect 985 MW of Firm imports and 17 MW of Firm exports for the 2012 summer. These capacity transactions are shown in Table 74.

Table 74: SERC-E Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	985	17	968
Expected	0	0	0
Total	**985**	**17**	**968**

Most contracts 10-year are agreements for the winter and summer peaking seasons. These include transactions that are both external and internal to the Region and/or the Assessment Area. All purchases are backed by Firm contracts for both generation and transmission and are not considered to be based on partial path reservations. Of the imports and exports shown, very few are associated with Liquidated Damages Contracts (LDCs), in which all contracts include “make-whole” provisions.

Entities within the SERC-E Assessment Area do not rely on resources outside the region for emergency imports, reserve sharing or outside assistance (external resources). Most entities within this area participate in RSAs with other VACAR utilities. Collectively, members of the VACAR RSA hold 1.5 times the largest single contingency (1,135 MW) in the VACAR RSA area to meet the Reference Margin. The Reserve Sharing Group is projecting adequate reserves throughout the 2012 summer.

Transmission

The current in service dates for transmission projects are not intended to be at risk for this assessment period. If delays occur that would result in reliability concerns, mitigating actions would be developed accordingly. These measures include re-dispatch of generation, operating procedures, and Special Protection Systems (SPS). On an ongoing basis, companies review and confirm or revise completion dates and monitor the construction status of all projects. Transmission projects planned to address a potential System Operating Limit or Interconnection Reliability Operating Limit commonly receive the highest priority for resources. New construction efforts are focused on completing facilities ahead of seasonal peak periods. Close coordination between construction management and operations planning ensures schedule requirements and completion requirements are well understood. Several large-scale construction projects are planned and will be implemented in phases around seasonal peak load periods to mitigate reliability concerns associated with line clearances and non-routine operating arrangements during periods of higher seasonal loads. Additionally, no significant transmission facility outages are projected to be out of service during the 2012 summer.

To address the need to maintain and enhance reliability, Progress Energy Corporation (PEC) is currently implementing a special transmission project in response to NERC recommendations to utilities entitled.[103] PEC is using Light Detection and Ranging (LiDAR) technology to analyze these conditions. Results from the project are currently being assessed and the project is scheduled to be completed by the end of 2014. Concerns from the plans analyses will be mitigated through an immediate remediation strategy. Other Transmission Operators in the SERC-E Assessment Area are also subject to the NERC recommendation and have not reported any negative transmission reliability or adequacy concerns.

Shifts from the use of coal to natural gas as a generation fuel source due to decreasing costs of natural gas have led to non-typical transmission line power loadings. However, no Transmission Operators in the SERC-E Assessment Area have reported any negative impacts on transmission adequacy.

Operations

Entities did not specify a need to perform special operating studies for the 2012 summer. No operational problems or constraints are anticipated during the assessment period. Operations designed such that the loss of multiple units can be occur without threatening reliability. The VACAR RSA is in place to support recovery from such extreme events. Generation maintenance schedules are carefully studied and reviewed to ensure reliability concerns are adequately addressed. Accordingly, most maintenance and new construction is scheduled prior to seasonal peak periods.

Since both distributed and variable generation are limited in the SERC-E and because entities maintain a diverse resource mix, special operating procedures are not needed for the integration of variable resources, or minimum demand over generation. Additionally, there are no identified concerns with meeting peak demands by calling on Demand Response resources. Entities do have restrictions on the

[103] *Consideration of Actual Field Conditions in Determination of Facility Ratings*. (Updated: November 30, 2010 (to revise schedule): http://www.nerc.com/fileUploads/File/Events%20Analysis/Ratings%20Recommendation%20to%20Industry%20FINAL-REVISED.pdf.

number of times that emergency Demand Response actions can be employed and these resources are readily available as needed.

Utilities within the area do not currently project environmental or regulatory restrictions for this summer. Lake levels are managed, to the extent weather conditions and inflows allow, mitigating hydro capacity limitations during seasonal peak load periods. There are no other unusual operating conditions anticipated that could impact reliability during the 2012 summer.

Vulnerability Assessment

Resource adequacy studies can help determine entity reserve margins in the SERC-E Assessment Area. No Special Protection Systems or remedial action schemes are installed in the SERC-E Assessment Area.

Entities in the SERC-E Assessment Area are not aware of any environmental and/or regulatory restrictions that could impact reliability during the 2012 summer. Lake levels are carefully managed, to the extent weather conditions and inflows permit, in order to mitigate hydro capacity limitations during seasonal peak load periods. There are no pending future environmental regulations that are expected to have an impact on the area during the 2012 summer.

Seasonal operating studies have identified no reliability concerns from projected operating conditions. No unusual operating conditions are anticipated for the upcoming summer. Entities will continue efforts to monitor the system through studies, assess line ratings, and improve the system to minimize any negative impacts on the system that could affect reliability for the 2012 summer. Annual planning activities continue to address both near-term and long-term facility needs. Overall, there are no known or projected significant conditions or generator outages that would reduce capacity in the area.

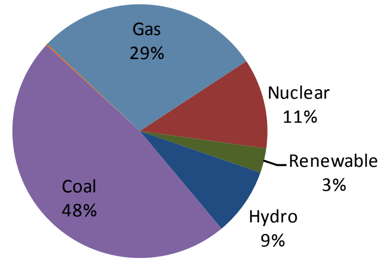
Fuel supply or delivery problems are not anticipated for the period. Utilities maintain enough diesel fuel to run the generation units for an order cycle of fuel. Firm gas supply and transportation contracts are monitored to align with inventory levels of coal and oil supply, natural gas storage, and generation capacity margins. Entities have ongoing communications with commodity and transportation suppliers to communicate near-term and long-term fuel requirements. These communications take into account market trends, potential resource constraints, and historical and projected demands. Regular discussions are framed to ensure potential interruptions can be mitigated and addressed in a timely manner.

Exchange agreements, alternative fuel, or redundant fuel supplies may also be used to mitigate emergencies in the fuel industry or economic scenarios. On-site fuel oil inventory allows for seven-day operations on some units. This was considered to be ample time to coordinate with the industry to obtain adequate supplies. Contracts are in place for months, and often years, into the future. Vendor performance is closely monitored and potential problems are addressed long before issues become critical. Contracts and market positions are considered to be diverse enough to mitigate any supply or delivery issues as they occur.

SERC-N

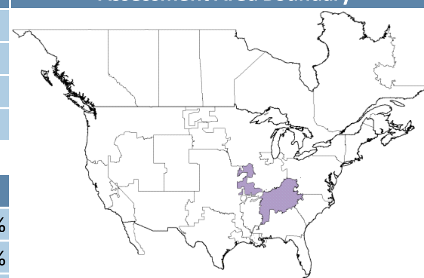
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	58,228	-
Future-Planned	878	-
Supply-Side Demand Response	0	-
Net Capacity Transactions	-1149	-
Anticipated	**57,957**	**33.03%**
Existing-Other and Future-Other	964	-
Prospective	**59,445**	**36.45%**
Reference Margin Level	-	**15.00%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**44,931**	**43,566**
Demand-Side Demand Response (2012)	-	1,536
Supply-Side Demand Response (2011)	1,915	-
Total Internal	**46,846**	**45,102**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	44,931	-3.04%
Actual Peak Demand	45,579	-4.42%
All-Time Summer Peak Demand	N/A*	N/A*

*Boundary changes applied in 2011.

Note: Additional information regarding the methods and assumptions used in the development of the SERC-N seasonal assessment can be found in Appendix I and on the NERC website.[104]

Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the SERC-N Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with load projections based on economic indicators, long-term weather forecasts, and historic load data.

The reserve margins for the SERC-N Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin is above the Reference Margin Level during the 2012 summer season.

A total of 878 MW of capacity additions will be added before or during the 2012 summer. According to the SERC-N Assessment Area demand forecast, Total Internal Demand has decreased from 46,846 MW to 45,102 MW since the 2011 summer. This equates to an annual growth rate of -3.7 percent.

Some transmission expansion will be required as a result of coal plants being idled. Additionally, severe widespread tornados caused significant system damage in April 2011 and again in March 2012. However, no transmission issues are expected to impact reliability during the 10-year assessment.

TVA's Clay, MS 500/161 kV substation is scheduled to be placed in service prior to the 2012 summer peak. This project will provide enhanced reliability for load in the vicinity.

[104] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

Planning Reserve Margins

As a result of lower loads and additional capacity, the SERC-N Assessment Area is projecting adequate planning reserve margins during the 2012 summer. Entity results show Anticipated Reserve Margin of 33.0 percent for the upcoming summer. Reserves for 2012 are anticipated to be adequate, assuming typical weather and operating conditions, due to past system development and the weakening of customer growth and energy usage in the area. Table 75 includes the 2011 and 2012 reserve margins for the SERC-N Assessment Area.

Table 75: SERC-N Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	15.00%	15.00%
Existing-Certain & Net Firm Transactions	27.98%	31.02%
Anticipated	27.98%	33.03%
Prospective	27.98%	36.45%

Demand

Decreases from the 2011 summer actual, 45,579MW, and peak demand forecast, 46,846MW, are primarily due to the slow recovery of the US and regional economies following the recession. The summer peak demand forecast is projected to be 45,102MW. Assumptions have been adjusted for normal weather and current economic conditions for both the United States and regional economies. Since the economic recession, some entities reported significantly adjustments to long-term models and recently enhanced near-term hourly forecast models. Table 76 includes the demand forecasts for the 2011 and 2012 summers for the SERC-N Assessment Area.

Table 76: SERC-N Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	44,931	43,566	-1,365	-3.04%
Total Internal	46,846	45,102	-1,744	-3.72%

Demand-Side Management

Demand Response and Energy Efficiency for the 2012 summer are projected to be 1,536 MW and 104 MW, respectively. These load control programs allow entities to reduce demand and control voltage as needed for reliability purposes. Demand Response is projected to be 3.4 percent of Total Internal Demand this summer, representing a 0.7 percentage point decrease from the 2011 summer. The primary source of current Demand Response is the direct load control program and the interruptible product portfolio. DLC includes a program with interruptible load contracted to and verified by a third party, and has companies that have contractually agreed to reduce their loads within minutes of a request. The estimate used in operational planning takes into account the amount of load available and is not a sum of total load under contract. Other Demand Response products that use control devices are also used by entities on air conditioning units and/or water heaters in residences. Entities are planning for increased demand reductions from these programs. The following are expected to increase in the upcoming years: interruptible demand and load control capabilities, distributor-operated voltage regulation programs, Demand Response pricing products, and introduction of two-way direct load control. Figure 47 and Table 77 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the SERC-N Assessment Area.

Figure 47: SERC-N Demand Response

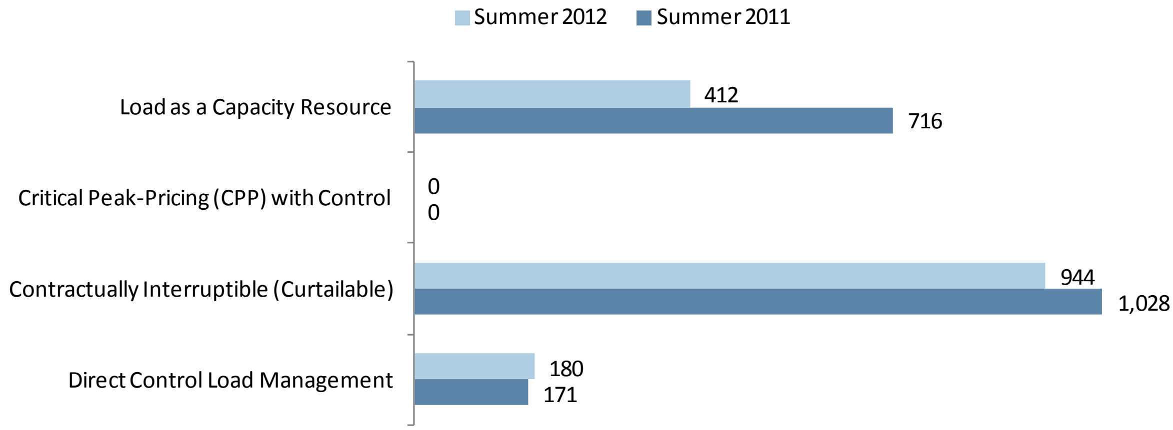


Table 77: SERC-N Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	171	180	0
Contractually Interruptible (Curtailable)	1,028	944	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	716	412	0
Total Demand Response	**1,915**	**1,536**	**0**
Percentage of Total Internal Demand	**4.09%**	**3.41%**	**0.00%**

Energy Efficiency programs, such as customer cost-saving energy surveys and audit evaluations, customer education, responsive pricing, residential/commercial conservation, electric thermal storage incentives, new construction (heat pump and geothermal), energy manufactured homes, air-source heat-pump programs (replacing resistance heat 10 years or older), low-income weatherization, low-income assistance, HVAC system improvements, industrial compressed-air programs. Various advanced lighting and third-party verification/measurement groups are currently in operation to residential and commercial customers. Commercial, industrial, and direct-served industry consumers have programs targeted to focus on efficiency improvements in HVAC, lighting, motors and controls, and other electrical-intensive equipment. By the end of 2012, entities are predicting 1,400 MW of additional reductions. These plans and goals recognize that improving peak demand reduction can help slow demand growth in a cost-effective manner, while addressing environmental concerns.

Generation

Utilities within the SERC-N Assessment Area expect to have 58,228 MW of Existing-Certain and 878 MW of Future-Planned capacity for the 2012 summer. Coal is the primary fuel source within SERC-N, representing 48.6 percent of Existing-Certain resources. No new Existing-Certain capacity has been added since the prior season. However, 878 MW of Future-Planned combined cycle resources are projected to be added prior to, and during the 2012 summer. Additionally, 71 MW is planned to be on inactive reserve this summer, while 412 MW is scheduled to be on 8 weeks of planned maintenance beginning the first week of September 2012. 167 MW is scheduled to be on planned maintenance for last week of September 2012. Table 78 includes projections of SERC-N resources for the 2011 and 2012 summer.

Table 78: SERC-N Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	57,610	58,228
Future-Planned	0	878
Supply-Side Demand Response	1,915	0
Net Capacity Transactions	427	-1,149
Anticipated	**59,952**	**57,957**
Existing-Other and Future-Other	0	964
Prospective	**59,952**	**59,445**

In accordance with an EPA settlement, 4 units (approximately 480 MW) are scheduled to retire by the end of 2015, and will idle in the spring of 2012.[105] Additionally, 6 units (111 MW each) will be taken out of service on August 1, 2015. The ability of utilities to reliably meet demand is not expected to be impacted by these planned outages. Scenario planning studies are routinely done to assess the impact on system reliability and adequacy for various assumptions of possible unit retirements that might occur during the planning window. The results of those studies are used in the annual planning process and as input to ongoing development of generating fleet strategic plans.

There is no reported behind-the-meter generation and 13 MW of Other/Unknown resources will be available during the 2012 summer. Additionally, extended outages are not expected during the summer period.

Variable resources in SERC-N are limited, although there are some purchases sourced from wind that are included in the transfer amount, and a small amount of solar supply that is part of a customer-owned generation buy-back program. The capacity values of wind contracts are usually based on applicable contract terms. The assumed contribution at the time of the system peak is 12 percent of the nameplate ratings of the associated wind generators (this factor is consistent with the credit applied by RTOs to other wind resources in that same geographical area). The contribution from the customer-owned solar resources is based on the solar insolation values for the area at the time of the summer peak. Entities will continue to evaluate these and other renewable resources as part of their integrated resource planning processes. In addition, no changes in planning procedures are needed for these small increments of variable resources. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 48 and Table 79.

[105] http://www.epa.gov/compliance/resources/cases/civil/caa/tvacoal-fired.html.

Figure 48: SERC-N Renewable Resources

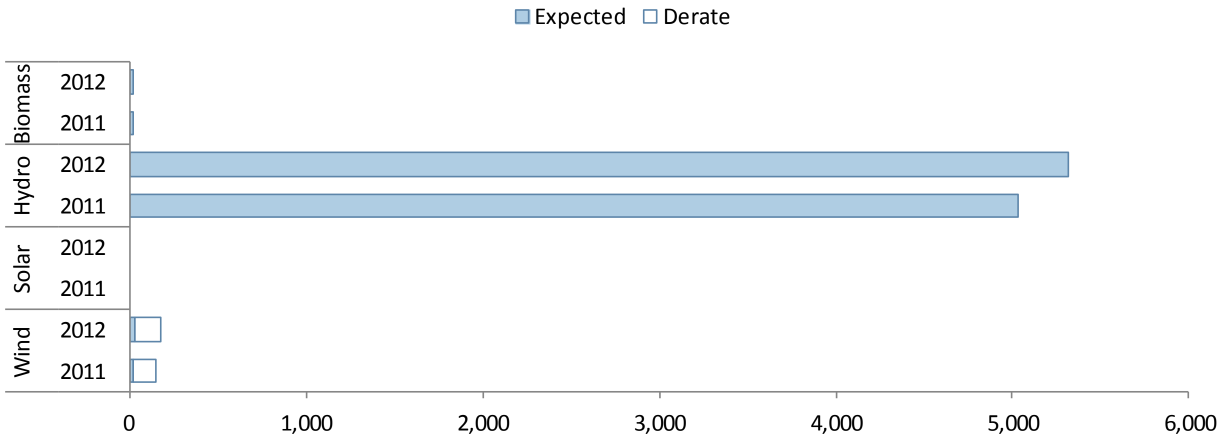


Table 79: SERC-N Renewable Resources

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	20	28	0	0	5,032	5,313	17	17
Derate	132	152	0	0	0	0	0	0
Nameplate	**152**	**179**	**0**	**0**	**5,032**	**5,313**	**17**	**17**

Capacity Transactions

Utilities within the SERC-N reporting area expect the following imports and exports in the table for the 2012 summer. A majority of these exports are backed by Firm contracts and do not include "make-whole" provisions. However, more than half of the imports reported by entities within SERC-N during the peak month are not backed by a Firm contract. These imports and exports have been accounted for in the reserve margin calculations for the reporting area. Most of the contracts in the area are 10-year agreements for the winter and summer peaking seasons. The majority of these imports and exports were reported to be backed by Firm contracts for both generation and transmission, and do not include "make-whole" provisions. Although not reported, import assumptions are not based on partial path reservations. On-peak capacity transactions projected for the 2012 summer are included in Table 80.

Table 80: SERC-N Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	263	1,412	-1,149
Expected	0	0	0
Total	**263**	**1,412**	**-1,149**

Contingency reserves and emergency imports are obtained from a variety of resources, including the Midwest ISO,[106] PJM, and the TEE Contingency Reserve Sharing Group (TCRSG). The TCRSG consists of three Balancing Authorities that are internal to the area and is intended to provide immediate response to contingencies. This enables the group to comply with the DCS standard and assist in preventing the curtailment of native load. Even though some entities rely on external resources for imports, there are some within the area that do not depend on short-term purchases or transfers from other Regions or

[106] Under Attachment RR of the Midwest ISO ancillary services market tariff.

Assessment Areas to meet demand requirements. Purchase agreements for imports do not include emergency arrangements.

Transmission

Currently, there are no major concerns with meeting in service dates for transmission improvements or specific projects needed to maintain reliability. If necessary, local area generation may be re-dispatched, or transmission elements reconfigured to alleviate anticipated next contingency overloads. Entities also have the option to invoke NERC TLR procedures[107] in scenarios that are not easily remedied by a local area solution.

Operations

Many entities within the SERC-N footprint perform routine operating studies (bi-annual load forecast study; monthly, weekly, and daily operational planning efforts; annual assessment of summer peak and temperature, etc.) to assess the system. These studies take into consideration weather, demand, and unit availability to help to address any risks. Based on the results of these studies, entities do not anticipate operational problems during the 2012 summer.

Due to the small amount of variable resources in the Assessment Area, no changes in operating procedures are needed. Recent additions have primarily been in the form of purchased power contracts sourced from wind resources in the mid-west that pose no significant challenges to current operational procedures. As a hedge against applying too much capacity credit for intermittent resources, on-peak impacts from those sources are adjusted to reflect net dependable capacity values to reduce the contribution to resource adequacy calculations and maintain a sufficient level of reliability.

Entities will continue to evaluate the potential to add renewable resources to their portfolios through integrated resource planning studies, and the outcome of those studies may prompt revisions to adequacy assessment procedures in the future. There are no significant operational changes, concerns, or special operating procedures related to distributed resource integration or minimum demand or over generation for the 2012 summer. However, some entities have reported that if low minimum demand occurs in the Midwest ISO region, entities may be required to take units off-line. Net scheduled interchanges, plus the minimum load conditions on all the generators, are assessed to see if adjustments can be made to address low minimum load conditions. System operators have the authority to take units off-line during real-time conditions to address minimum generation issues as needed.

The limited amount of Demand Response in the area does not pose any reliability concerns for this summer. Currently, Demand Response is treated as a resource and not as a reduction in load for some entities, and scenario planning is employed to evaluate the impact on system reliability for differing assumptions of Demand Response effectiveness. Programs that establish a measurement and verification for the program are in progress to track and refine estimates of Demand Response benefits.

Utilities are aware of the potential for regulatory restrictions as a result of environmental rules that will impact generating resource operations. These can include emissions restrictions as well as cooling water source temperature regulation, which can lead to plant de-rates. Routine internal communications

[107] http://www.nerc.com/page.php?cid=5%7C67.

practices will alert operational planners at the onset to any potential regulatory impact to plant operations. At that time, limitations can be factored into operational planning analysis. Mitigation plans are typically developed to reduce system reliability risks. Additionally, some units have been derated due to higher than expected river temperatures and/or lower water flows. As a result, these derates have been partially mitigated for the coming summer season. However, reserves are expected to be well above 15 percent, so any thermal derates should not impact system reliability. Overall, there are no unusual operating conditions anticipated that could impact reliability for the summer.

Vulnerability Assessment

Resource adequacy assessments covering the next 36 months are performed monthly to assist in identifying limitations or constraints that may impact seasonal adequacy. Long-term adequacy assessments based on 20 years of capacity planning are also performed to make decisions relative to resource acquisitions and project development timelines to ensure system reliability. No system reliability concerns for the period have been identified in the latest resource adequacy studies. Resource availability, fuel availability, and hydro and reservoir conditions are expected to be normal during the summer. However, entities are monitoring adjustments and results to the studies as a consequence of environmental regulations. Currently, there are no Special Protection Systems in SERC-N.

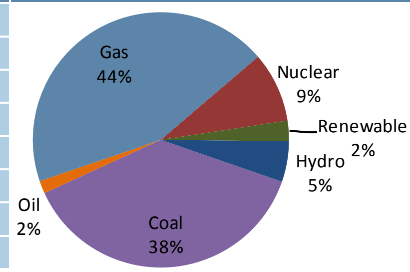
As stated in the previous section, utilities are aware of the risks associated with the current and pending environmental regulations, and have pre-established operational procedures to avoid or address system reliability impacts when identified.

There are currently no anticipated unit retirements that are projected to significantly impact system reliability, nor are there any indications that there will be insufficient time to perform any required retrofits. Entities will continue to conduct scenario planning studies to assess the impact on system reliability and adequacy for various assumptions of possible unit retirements during the period. The results of those studies are used in the annual planning process and provide input to ongoing development of generating fleet strategic plans. The effects of possible future long-term maintenance outages on off-peak reliability are believed to be negligible. Ongoing mitigation plans are developed to reduce system reliability risks. Mitigations may include purchases, new generation, or reliance on reserves. However, as with every regulation that is promulgated, entities will continue to adapt their operations, as needed (*i.e.*, install controls), in order to comply with new regulatory requirements without affecting reliability.

SERC-SE

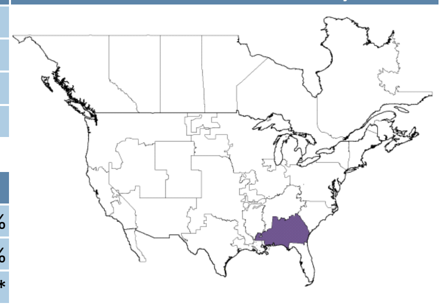
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	64,342	-
Future-Planned	50	-
Supply-Side Demand Response	0	-
Net Capacity Transactions	-1509.6	-
Anticipated	**62,883**	**33.45%**
Existing-Other and Future-Other	1,916	-
Prospective	**64,799**	**37.52%**
Reference Margin Level	-	**15.00%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**47,610**	**47,121**
Demand-Side Demand Response (2012)	-	1,774
Supply-Side Demand Response (2011)	1,704	-
Total Internal	**49,314**	**48,895**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	47,610	-1.03%
Actual Peak Demand	50,309	-6.34%
All-Time Summer Peak Demand	N/A*	N/A*

*Boundary changes applied in 2011.

Note: Additional information regarding the methods and assumptions used in the development of the SERC-SE seasonal assessment can be found in Appendix I and on the NERC website.[108]

Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the SERC-SE Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The reserve margins for the SERC-SE Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

A total of 80 MW of capacity additions will be added during the 2012 summer. According to the SERC-SE Assessment Area demand forecast, Total Internal Demand has decreased from 49,314 MW to 48,895 MW since the 2011 summer. This equates to an annual growth rate of -0.8 percent.

Planning Reserve Margins

The SERC-SE Assessment Area is projecting an adequate planning reserve margin throughout the 2012 summer. Utilities do not adhere to any Regional or Assessment Area targets or reserve margin criteria. However, the State of Georgia requires maintaining at least 13.5 percent near-term (less than 3 years) and 15 percent long-term (3 years or more) reserve margin levels for investor-owned utilities. Most entities use the NERC Reference Margin Level of 15 percent, assigned by NERC to Assessment Areas that

[108] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

do not provide a Reference Margin Level. Contributing factors to adequate margins can be attributed to the addition of resources and the expiration or acquisition of Firm purchase contracts. Reserves for the 2012 summer are also anticipated to be adequate due to reductions in load forecasts, resulting from the recent recession and economic downturn, assuming typical weather and operating conditions. Table 81 includes the 2011 and 2012 reserve margins for the SERC-SE Assessment Area.

Table 81: SERC-SE Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	15.00%	15.00%
Existing-Certain & Net Firm Transactions	24.91%	33.34%
Anticipated	24.91%	33.45%
Prospective	31.60%	37.52%

Demand

Decreases from the 2011 peak demand forecast (49,314 MW) and this summer's peak demand forecast, which is projected to be 48,895 MW, are primarily due to the continuation of a slow economic recovery. The 2011 summer actual peak demand (50,309 MW) was slightly greater than the 2011 peak demand forecast, and entities in the area have found that most of the recovery is led by industrial-class load growth. A change in the class composition due to this unbalanced recovery has lowered the peak forecast for this summer. Historically, economic growth can be rapid following a deep recession. The economic forecasts used in load forecasting, indicate that the current recovery phase has remained expectations. The economic fundamentals of the Region are still strong and forecasters are anticipating the recovery of the job market will yield additional growth, including in the housing market, which will lead to a period of self-sustaining load growth. Table 82 includes the demand forecasts for the 2011 and 2012 summers for the SERC-SE Assessment Area.

Table 82: SERC-SE Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	47,610	47,121	-489	-1.03%
Total Internal	49,314	48,895	-419	-0.85%

Demand-Side Management

Demand Response is projected to be 1,774 MW, with Energy Efficiency included in the load forecast. These programs allow entities within the Assessment Area to have better ability to control various amounts of load and capacity when needed for reliability purposes. Extreme real-time pricing response is considered as a capacity resource. The distribution-level efficiency programs in SERC-SE involve adding capacitors on distribution circuits to reduce line losses and to smooth out voltage drop across the circuit. In addition, the activation of Conservation Voltage Reduction (CVR) helps reduce voltage on the distribution circuit at the voltage regulator or load tap transformer, reducing the customer demand. Additional objectives of some of the SERC-N programs are as follows:

- Help reduce the need to build or purchase capacity
- Respond to volatile wholesale energy markets

- Improve the efficiency (load factor) as well as the utilization of generation, transmission, and distribution systems
- Provide low cost energy to member cooperatives
- Increase off-peak kWh sales

Demand Response is projected to be 3.6 percent of Total Internal Demand, a 0.1 percentage point increase since the 2011 summer. Figure 49 and Table 83 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the SERC-SE Assessment Area.

Figure 49: SERC-SE Demand Response

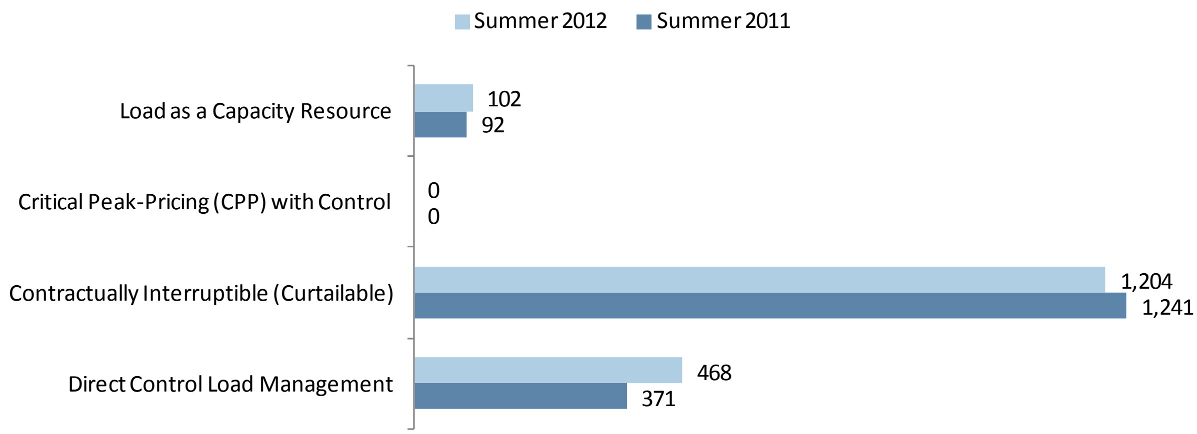


Table 83: SERC-SE Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	371	468	0
Contractually Interruptible (Curtailable)	1,241	1,204	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	92	102	0
Total Demand Response	**1,704**	**1,774**	**0**
Percentage of Total Internal Demand	**3.46%**	**3.63%**	**0.00%**

Generation

Utilities within the SERC-SE Assessment Area expect to have 64,342 MW of Existing-Certain, 1,836 MW of Existing-Other, 0 MW of Existing-Inoperable capacity on-peak. This capacity is projected to help meet demand during this time period. Gas-fired dual fuel units[109] are the primary source of fuel within SERC-SE, making up 45.4 percent of Existing-Certain resources. 841 MW of Existing-Certain resources have been added since the prior season. Additionally, 130 MW of gas-fired Future-Planned resources are projected to be added during the summer period. Entities have reported no unit retirements during the months of June through September. No significant negative impacts on capacity are anticipated for the period. Table 84 includes projections of SERC-SE resources for the 2011 and 2012 summer.

[109] With oil backup.

Table 84: SERC-SE Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	61,072	64,342
Future-Planned	0	50
Supply-Side Demand Response	1,704	0
Net Capacity Transactions	-1,179	-1,510
Anticipated	**61,597**	**62,883**
Existing-Other and Future-Other	3,301	1,916
Prospective	**64,898**	**64,799**

Approximately 841 MW of new generation has been added since the last summer season. There are no projections for generator up-rates other generation being taken out of service during the 2012 summer. In addition, no generation will be brought back into service. No behind-the-meter generation was reported, while 417 MW of Other/Unknown resources are expected to serve during the 2012 summer. No extended outages are projected. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 50 and Table 85.

Figure 50: SERC-SE Renewable Resources

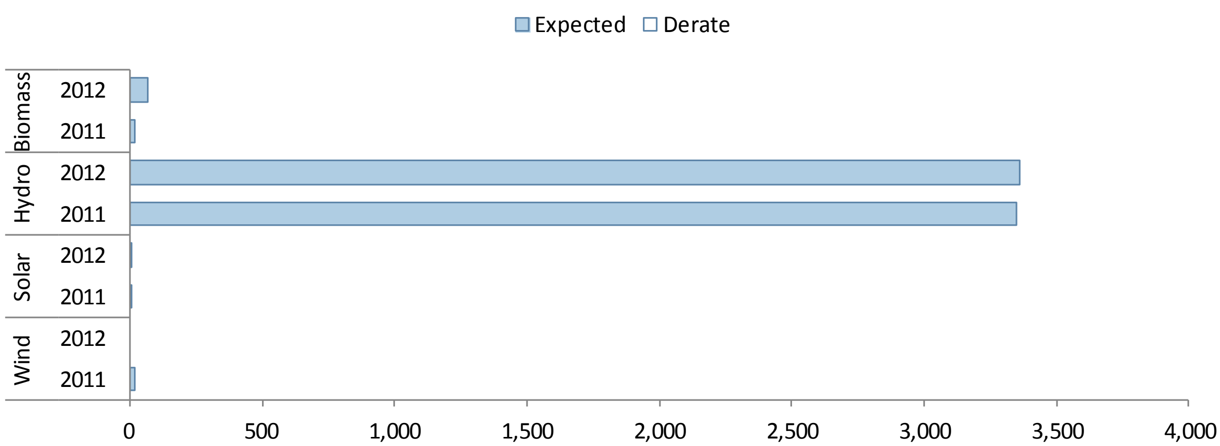


Table 85: SERC-SE Renewable Resources

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	20	0	2	4	3,350	3,360	17	67
Derate	0	0	0	0	0	0	0	0
Nameplate	**20**	**0**	**2**	**4**	**3,350**	**3,360**	**17**	**67**

Capacity Transactions

Utilities within the SERC-SE Assessment Area expect the following imports and exports listed in Table 86 for the 2012 summer. These imports and exports have been accounted for in the reserve margin calculations for the Assessment Area. The majority of the contracts in the area are yearly Firm agreements typically lasting at least five years. Yearly Firm agreements of five years or more are given "Rollover Rights," meaning the contract can be renewed within one year notice of contract expiration. All imports and exports were reported to be backed by Firm contracts for both generation and transmission, but none are associated with Liquidated Damages Contracts (LDC), or considered "make whole." On-peak capacity transactions projected for the 2012 summer are included in Table 86.

Table 86: SERC-SE Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	1,150	2,660	-1,510
Expected	0	0	0
Total	**1,150**	**2,660**	**-1,510**

Reporting entities maintain emergency-reserve sharing agreements (RGA) with organizations such as the SPP Reserve Sharing Group and entities internal to the area (approximately 250 MW). Other contract agreements with neighboring utilities provide capacity for outages of specific generation. Total emergency generation from these imports were not reported, but are available as needed. Overall, entities are not dependent on outside imports or transfers to meet load.

Transmission

Currently, there are no concerns with meeting in service dates for transmission improvements or projects needed to maintain reliability. Entities consistently evaluate the transmission system through operating studies and a model construction process. These evaluations address any potential delays in construction and are used to determine switching procedures, operating procedures, or near-term improvements that may be necessary, should an in service date of a bulk facility be adjusted. The Reliability Coordinator (RC) and Transmission Operators (TO) also work with impacted entities to coordinate construction and outage schedules to maintain reliable operations.

Operations

SERC-SE entities perform studies of operating conditions for 12 to 13 months into the future. These studies include the most up-to-date information regarding load forecasts, transmission and generation status, and Firm transmission commitments for the time period studied and are often updated on a monthly basis. Reliability studies are conducted on one week out, two-day-out and next-day conditions. Studies are updated as changing system conditions warrant. The current operational planning studies do not identify any operational problems. Some entities have conducted assessments of the impact of the Environmental Protection Agency's (EPA) Cross-State Air Pollution Rule (CSAPR) requirements on system dispatch. Although constraints were identified, the EPA stayed implementation of the rule during the study. Currently, it is uncertain at this time whether CSAPR requirements will be reinstated in 2012.

As stated above, entities within the area are constantly updating studies to assess the changes of system conditions as a result of the recent EPA requirements. The current operational planning studies for the period do not identify any operational problems. Entities in this area will continue to manage fossil generating units operating limits related to air and/or water quality. These are derived from both Federal and state regulations. A number of these units have unique limits on operations and/or emissions; some are annual limits while others are seasonal. These restrictions are continually managed in the daily operation of the system while maintaining reliability. Similarly, hydroelectric units in the area are run in cooperation with the U.S. Army Corps of Engineers to maintain water levels and river flow as well as system reliability. Overall, no existing conditions are projected to impact the reliability on the Bulk Power System because of environment restrictions.

The Southern control area routinely experiences significant loop flows due to transactions external to the control area itself. The availability of large amounts of excess generation within the Southeast U.S. results in fairly volatile day-to-day scheduling patterns. The transmission flows are often more dependent on the weather patterns, fuel costs, or market conditions outside the Southern control area rather than by loading within the control area. Significant changes in gas pricing dramatically impact dispatch patterns. All transmission constraints identified in current operational planning studies for the summer assessment period can be mitigated through generation adjustments, system reconfiguration, or system purchases. Overall, there are no unusual operating conditions anticipated that could impact reliability for the summer.

Vulnerability Assessment

Resource adequacy is determined by extensive analysis of costs associated with expected un-served energy, market purchases and new capacity. These costs are balanced to identify a minimum cost point that is the optimum reserve margin level. No system reliability concerns for the period have been identified in the latest resource adequacy studies. Variable resources have been procured and are not presently relied upon to meet resource adequacy requirements. Resource availability, fuel availability and hydro and reservoir conditions are expected to be normal during the summer.

There are no existing Special Protection Systems (SPS) in the SERC-SE Assessment Area. No SPSs have been installed since last summer, nor are there any plans to install SPSs this summer.

A significant reliability concern involves the uncertainty in generating resource availability in 2015 and beyond, introduced by the recent implementation of EPA MATS rules and other pending environmental rules being promulgated. The SBA Planning Authority is working with Load Serving Entities and Generator Operators to assess resource availability and potential unit retirements. Potential additional transmission enhancements have been identified and will be re-assessed during the spring planning cycle for possible inclusion in 2012 expansion plans. These assessments may also lead to requests associated with MATS implementation requirements to operating units beyond 2015 as needed to maintain reliability.

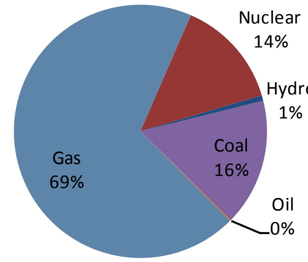
A related reliability concern involves the extensive generation and transmission construction work that must be completed prior to the 2015 implementation of MATS. The Reliability Coordinator and Transmission Operators are working with impacted entities to coordinate construction and outage schedules to maintain reliable operations.

For the upcoming summer season, there are no expected issues or concerns surrounding the timeline to install environmental controls in the SERC-SE Assessment Area to meet regulatory requirements. Additionally, no units are expected to be out of service during the 2012 summer season due to the installation of environmental controls. The fuel supply infrastructure, fuel delivery system, and fuel reserves are all adequate to meet peak gas demand.

SERC-W

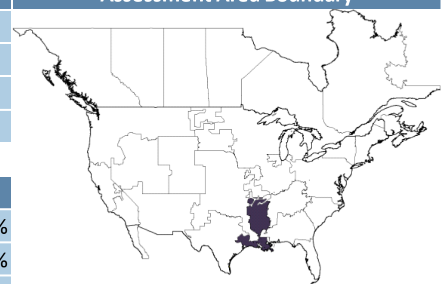
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	37,145	-
Future-Planned	1,978	-
Supply-Side Demand Response	0	-
Net Capacity Transactions	-2554	-
Anticipated	**36,569**	**44.02%**
Existing-Other and Future-Other	874	-
Prospective	**37,443**	**47.46%**
Reference Margin Level	-	**15.00%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**24,228**	**25,392**
Demand-Side Demand Response (2012)	-	11
Supply-Side Demand Response (2011)	873	-
Total Internal	**25,101**	**25,403**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	24,228	4.80%
Actual Peak Demand	25,585	-0.75%
All-Time Summer Peak Demand	N/A*	N/A*

*Boundary changes applied in 2011.

Note: Additional information regarding the methods and assumptions used in the development of the SERC-W seasonal assessment can be found in Appendix I and on the NERC website.[110]

Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the SERC-W Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The reserve margins for the SERC-W Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin is above the Reference Margin Level during the 2012 summer season.

A total of 1,978 MW of capacity additions are projected to be added during the summer of 2012. All transmission upgrades associated with the capacity additions have been completed and placed into service. According to the SERC-W Assessment Area demand forecast, Total Internal Demand has increased from 25,101 MW to 25,403 MW since the 2011 summer. This equates to an annual growth rate of 1.2 percent.

Overall, there are no other anticipated reliability concerns for the 2012 summer. To minimize potential reliability issues during the 2012 summer, SERC-W entities studied reliability with a critical and conservative approach. Any issues that result from the studies are addressed within the appropriate timeframe. Curtailment processes and emergency response plans are routinely updated. As necessary,

[110] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

local area procedures, redispatch, and operating guidelines will be implemented to maintain reliability for the summer. Because Energy Emergency Alerts (EEAs) have been issued in the past for the Acadiana Load Pocket, the SPP Independent Coordinator of Transmission-Entergy monitored this area closely and was prepared to implement mitigation plans necessary as part of its Reliability Coordinator function. A two-phase joint project to construct a 230 kV overlay in the Acadiana Load Pocket is scheduled to be completed prior to the 2012 summer. Phase 1 of the project was completed in the fall of 2011 and the Acadiana Load Pocket did not experience any reliability issues during 2011. Additionally, Entergy is currently planning to install a dynamic voltage device to provide voltage support in the south-central Arkansas by the summer of 2013.

Planning Reserve Margins

The SERC-W Assessment Area is projecting adequate planning reserve margins during the 2012 summer, as none of the three categories will fall below the NERC Reference Margin Level of 15 percent. Entities within this area do not adhere to any reserve margin criteria set by the Regional or Assessment Area. Contributing factors to adequate margins include existing resources, limited and long-term purchase contracts, as well as potential deactivations and anticipated unit outages to plan and procure resources as needed to meet the Reference Margin Level when developing plans for the season. Individual entity criteria have also helped to establish resource adequacy by allocations assigned as a member of the SPP Reserve Sharing Group, Balancing Authority's most severe single contingency, load forecast, and reserve requirement using historical allocations, and Loss-of Load expectation studies (1 day in 10 years). There are no other anticipated reliability concerns projected for the 2012 summer conditions. Table 87 includes the 2011 and 2012 reserve margins for the SERC-W Assessment Area.

Table 87: SERC-W Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	15.00%	15.00%
Existing-Certain & Net Firm Transactions	46.19%	36.23%
Anticipated	46.19%	44.02%
Prospective	55.31%	47.46%

Demand

Overall, there are no significant differences in the 2011 summer actual (25,585 MW) and peak demand forecast (25,101 MW) to the 2012 summer forecast (25,403 MW). Increases are primarily a reflection of retail load growth and increases in wholesale load. Forecast assumptions are unchanged since the 2011 forecast. Table 88 includes the demand forecasts for the 2011 and 2012 summers for the SERC-W Assessment Area.

Table 88: SERC-W Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	24,228	25,392	1,164	4.80%
Total Internal	25,101	25,403	302	1.20%

Demand-Side Management

Demand Response and Energy Efficiency are projected to be 11 MW and 0 MW, respectively. These programs are used to reduce peak demand on entity systems within the area. There is no significant change in the amount of demand response since last summer. Demand-Side Management (DSM) programs among the utilities in SERC-W include: interruptible load programs for larger customers, direct-control load management programs for agricultural customers, and a range of conservation/load management programs for all customer segments. There are no significant changes in the amount and availability of load management and interruptible demand since last year. Figure 51 and Table 89 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the SERC-W Assessment Area.

Figure 51: SERC-W Demand Response

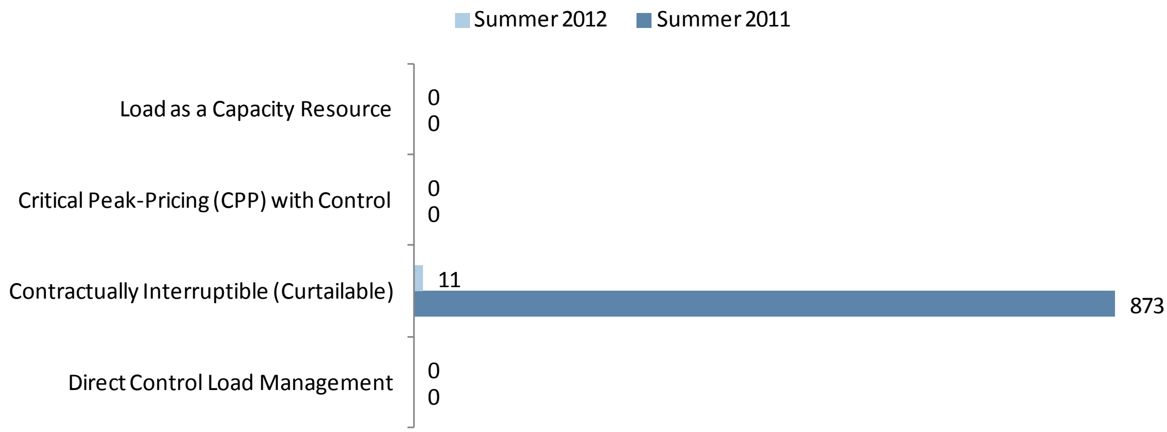


Table 89: SERC-W Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	0	0	0
Contractually Interruptible (Curtailable)	873	11	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	0	0	0
Total Demand Response	**873**	**11**	**0**
Percentage of Total Internal Demand	**3.48%**	**0.04%**	**0.00%**

Generation

Companies within the SERC-W Assessment Area expect to have 37,145 MW of Existing-Certain, 874 MW of Existing-Other, 967 MW of Existing-Inoperable capacity on-peak. This capacity is projected to help meet demand during this time period. Gas generation is the primary fuel source within this area, representing 68.6 percent of Existing-Certain resources. No Existing-Certain capacity has been added since the prior season. However, 1,978 MW of Future-Planned resources are projected to be added during the summer season. Entities have reported no unit retirements during the 2012 summer season. Table 90 includes projections of SERC-W resources for the 2011 and 2012 summer.

Table 90: SERC-W Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	34,713	37,145
Future-Planned	0	1,978
Supply-Side Demand Response	873	0
Net Capacity Transactions	1,110	-2,554
Anticipated	**36,696**	**36,569**
Existing-Other and Future-Other	3,419	874
Prospective	**40,115**	**37,443**

There no projections for generators being put out of service during the period and no known generator up-rates. In addition, 57 MW will be brought back into service for the period. There will be no behind-the-meter generation during the 2012 summer. No ongoing long-term outages have been reported. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 52 and Table 91.

Figure 52: SERC-W Renewable Resources

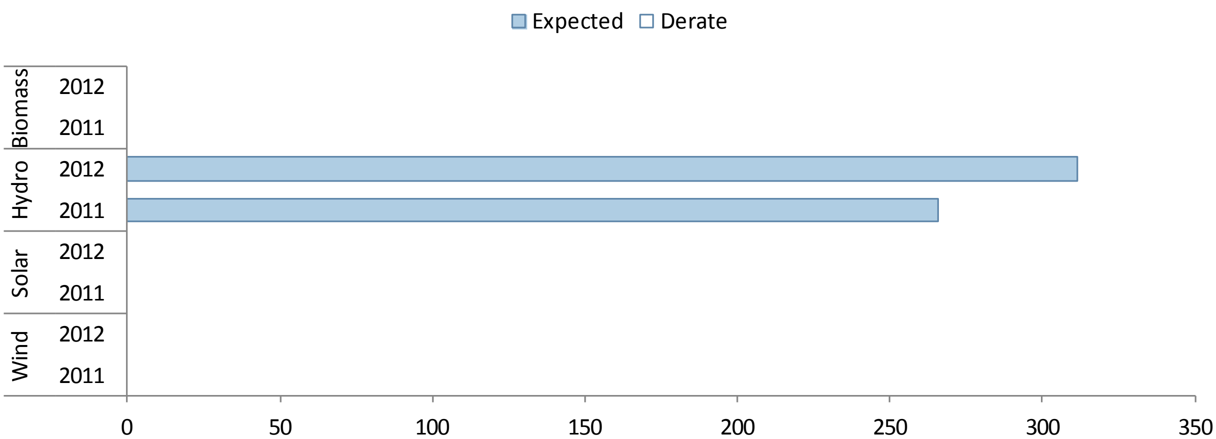


Table 91: SERC-W Renewable Resources

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	0	0	0	0	266	311	0	0
Derate	0	0	0	0	0	0	0	0
Nameplate	**0**	**0**	**0**	**0**	**266**	**311**	**0**	**0**

Capacity Transactions

These imports and exports projected for the SERC-W Assessment Area have been accounted for in the reserve margin calculations. Most of the contracts in the area are agreements for a 10-year period for the winter and summer peaking seasons. On-peak capacity transactions projected for the 2012 summer are included in Table 92.

Table 92: SERC-W Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	180	2,734	-2,554
Expected	0	0	0
Total	**180**	**2,734**	**-2,554**

Reporting entities in the area are dependent on certain imports, transfers, or contracts to meet the demand. Most entities are members of the Southwest Power Pool (SPP) Reserve Sharing Group (RSG). SPP participants generally transfer reserves into the area to either replace largest contingency or supply generation to the area. These reserves are not relied on in the resource adequacy assessment, included as capacity or considered in planning reserve margins. System operators generally coordinate the scheduling and transmitting of the reserves. Total emergency generation from these imports were not reported, but are available as needed.

Transmission

Entities within the Assessment Area are not expecting any delays in meeting in service dates for projects scheduled for the summer assessment period. Additionally, there are no significant transmission facility outages that impact bulk electric system reliability. Prior to approval of any proposed maintenance outages, studies are completed to identify any impacts on reliability.

Operations

Companies within the SERC-W Assessment Area regularly participate in SERC NTSG seasonal reliability studies and in the ERAG MRO-RFC-SERC West-SPP (MRSWS) interregional studies. These studies do not exactly include the new SERC-W defined area transfer capabilities, but the SERC-W Assessment Area is very similar to one of the defined company areas that are included in the NTSG 2011 study. These studies test import capabilities into the area and are expected to predict increases or decreases for all examined transfer directions. The interregional transmission transfer capabilities are not currently available, partially due to the recent decision to report as a SERC-W Assessment Area.

Entities are currently studying potential approaches for incorporating variable resources into its planning processes. Due to an insignificant amount of variable generation connected to the distribution system, there are no concerns about integrating these resources onto the system. Wind agreements are used as a tool to allow operators to enhance reliability and can be used in situations such as curtailing for TLR and managing minimum generation problems. However, there are no concerns in this area for the upcoming season. Additionally, entities are not anticipating reliability concerns resulting from availability of Demand Response resources, environmental regulation constraints, or unusual operating conditions that could potentially impact reliability.

Vulnerability Assessment

Existing and owned resources, limited and long-term purchase contracts, as well as potential deactivations and anticipated unit outages to plan and procure resources needed to meet the Reference Margin Level are considered when developing the one-year and 10-year resource plan. The latest resource adequacy studies performed for the 2012 summer do not show concerns for reliability of the system. Resource availability, fuel availability and hydro conditions are expected to be normal during the summer, except for possible hydro limitations in Texas as stated above. Loss-of-Load studies are performed annually for the current year based on updated load forecast and unit availability data. The long-term test of resource adequacy is met by achieving a 16.85 percent Reference Margin Level.

The Acadiana Load Pocket located in southern Louisiana did not experience any reliability issues in 2011 winter or summer. The addition of the 230 kV lines from Roark to Sellers road and Sellers Road to Meaux in spring 2011, along with the energizing of the Segura 230 kV line in fall 2011, alleviated a portion of the most limiting elements. The 230 kV line from Labbe to Bonin was energized in February 2012, and two other 230 kV lines from Wells to Labbe and Labbe to Sellers Rd. are expected to be energized this summer. Completion of these projects should further alleviate transmission congestion in this area and will conclude the planned Acadiana Load Pocket projects.

No Special Protection Systems (SPS) have been installed in the SERC-W Assessment Area since last summer in lieu of planned bulk power transmission facilities.

There are no environmental or regulatory restrictions projected within the Assessment Area. The CSAPR rules, which have been stayed, were not expected to result in any new Reliability Must Run (RMR) units in SERC-W. In the event that there were insufficient allowances to operate existing RMR units at historical levels, it was still possible to run these units at reduced production levels while still ensuring grid reliability. Additional flexibility was expected with the October, 2011 proposed revision. The increased flexibility allowed by this revision created addition possibilities for compliance, including interstate allowance purchases. Prior to the proposed October limits, some utilities in SERC-W had identified potential transmission upgrades in which acceleration of existing transmission projects was being considered. These projects are current Bulk Electric System projects in various stages of planning, design, and construction. However, with the proposed October limits, no Bulk Electric Systems projects were identified in which acceleration prior to 2012 was required.

Utilities in the SERC-W Assessment Area do not anticipate significant or immediate impacts to system reliability due to the combined effects of CSAPR and other emerging environmental regulations. While the short implementation period allowed for CSAPR initially created concern, other emerging rules are expected to have varying implementation dates that will provide adequate time for planning and execution of control projects. Additionally, coal plants, which are most affected by emerging regulations, are positioned relatively well in regard to their capacity and age, such that most projected environmental projects are currently estimated to be economically viable and not expected to result in early retirements.

Utilities have also indicated that, depending on the deadlines created by the final MACT rule, applicable deadlines for the installation of major pollution control equipment could be problematic for individual plants. These problems are compounded by the uncertainty over the Regional Haze state implementation plan requirements, pending eventually approval by the EPA, could require the installation of additional retrofits at certain plants. Utilities generally believe that impacted coal plants are faced with timing, rational project management, permitting issues, and state public service commission approval. The most immediate threat to reliability is likely to occur in the long-term, considering that many units will be impacted by requirements to implement 316(b) controls and address any reductions driven by lower National Ambient Air Quality Standards (NAAQS). While these regulations could be impactful as soon as 2020, utilities generally do not anticipate the suite of EPA regulations to result in significant facility retirements or generation reductions.

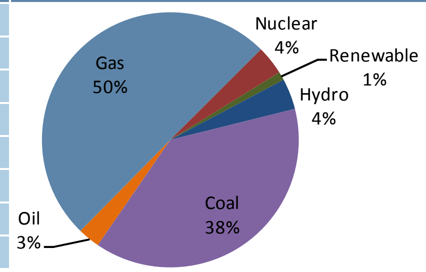
Fuel supply or delivery problems are not anticipated for the summer season. Utilities maintain enough diesel fuel to run the generation units for an order cycle of fuel. Firm gas supply and transportation contracts are monitored to align with inventory levels of coal and oil supply, natural gas storage and generation capacity margins. Entities have ongoing communications with commodity and transportation suppliers to communicate near-term and long-term fuel requirements. These communications take into account market trends, potential resource constraints, and historical and projected demands. Regular discussions are framed to ensure potential interruptions can be mitigated and addressed in a timely manner.

Exchange agreements, alternative fuel, or redundant fuel supplies may also be used to mitigate emergencies in the fuel industry or economic scenarios. On-site fuel oil inventory allows for seven-day operations on some units. This was considered to be ample time to coordinate with the industry to obtain adequate supplies. Contracts are in place for months, and often years, into the future. Vendor performance is closely monitored and potential problems are addressed long before issues become critical. Contracts and market positions are considered to be diverse enough to mitigate any supply or delivery issues as they occur.

SPP

2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	63,547	-
Future-Planned	2	-
Supply-Side Demand Response	0	-
Net Capacity Transactions	1308.651516	-
Anticipated	**64,908**	**22.66%**
Existing-Other and Future-Other	2,492	-
Prospective	**71,831**	**35.75%**
Reference Margin Level	-	**13.60%**

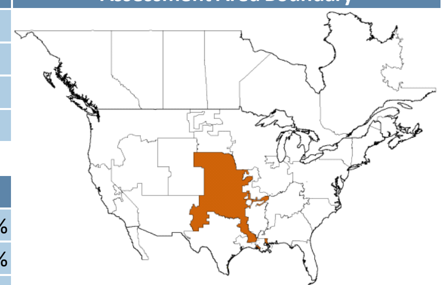
On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**52,261**	**52,915**
Demand-Side Demand Response (2012)	-	1,136
Supply-Side Demand Response (2011)	1,252	-
Total Internal	**53,512**	**54,051**

2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	52,261	1.25%
Actual Peak Demand	55,352	-4.40%
All-Time Summer Peak Demand (August 2, 2011)	51,713	2.32%

Assessment Area Boundary



Note: Additional information regarding the methods and assumptions used in the development of the SPP seasonal assessment can be found in Appendix I and on the NERC website.[111]

Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the Southwest Power Pool Regional Transmission Organization (RTO) Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The SPP RTO Assessment Area's reserve margins are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

A total of 2 MW of capacity additions will be added during the 2012 summer. According to the SPP RTO, the Total Internal Demand forecast has increased from 53,512 MW to 54,051 MW since the 2011 summer. This equates to an annual growth rate of 1 percent.

Planning Reserve Margins

SPP criteria require members to maintain a minimum capacity margin of 12 percent (13.6 percent Reference Margin Level). The SPP RTO is projected to have an adequate Anticipated Reserve Margins of 22.66 percent, well above the SPP Reference Margin of 13.6 percent. This level of adequacy is supported by the SPP RTO's available generation fleet and the minimal demand increase projected for this summer. 2011 and 2012 summer Planning Reserve Margins for the SPP Assessment Area are presented in Table 93.

[111] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

Table 93: SPP Reserve Margins

Reserve Margin	Summer Peak Forecast	
	2011	2012
Reference Margin Level	**13.60%**	**13.60%**
Existing-Certain & Net Firm Transactions	**20.62%**	**22.57%**
Anticipated	**21.11%**	**22.66%**
Prospective	**25.00%**	**35.75%**

Demand

The projected non-coincident Total Internal Demand forecast for the 2011 summer peak was 53,512 MW, compared with the projected 2012 summer peak demand forecast of 54,051 MW. The actual 2011 summer peak demand was 55,352 MW. The 2011 summer actual peak demand was higher than the forecasted peak demand due to extreme hot weather experienced across the SPP RTO footprint. Table 94 includes the demand forecasts for the 2011 and 2012 summers for the SPP Assessment Area.

Table 94: SPP Demand

Demand	Summer Peak Forecast			
	2011	2012	Change (MW)	Change (%)
Net Internal	**52,261**	**52,915**	**654**	**1.25%**
Total Internal	**53,512**	**54,051**	**539**	**1.01%**

The SPP RTO's annual growth rate is consistent with the 2011 assessment numbers. Most areas in the footprint indicated low to moderate load growth, with only a few areas indicating a slow-down in demand growth projections.

Demand-Side Management

SPP RTO members provide individual Demand Response programs as reductions in the respective load forecasts. The SPP RTO summer assessment reports 911 MW of interruptible and controllable demand and 226 MW of load management.[112] Additionally, the SPP RTO members have reported 237 MW of Energy Efficiency programs to be available during the 2012 summer peak.[113] Figure 53 and Table 95 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the SPP Assessment Area.

[112] SPP RTO does not have the means to measure or verify these Demand Response programs.

[113] The demand response and energy efficiency peak values represent the peak value during the four month summer season and may not be coincident with the peak demand month.

Figure 53: SPP Demand Response

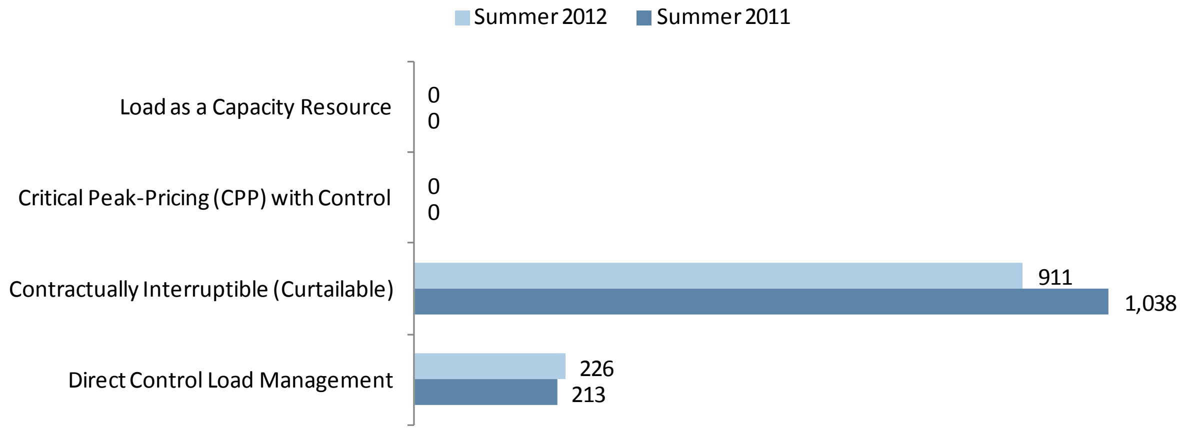


Table 95: SPP Demand Response

Demand Response	Summer Peak Forecast		
	Supply-Side (Capacity Resource)	Demand-Side (Load-Modifying)	Supply-Side (Capacity Resource)
	2011	2012	2012
Direct Control Load Management	213	226	0
Contractually Interruptible (Curtailable)	1,038	911	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	0	0	0
Total Demand Response	**1,252**	**1,136**	**0**
Percentage of Total Internal Demand	**2.34%**	**2.10%**	**0.00%**

Westar Energy launched its voluntary Demand Response program, WattSaver, in September 2009. WattSaver is open to single and multi-family residential customers, as well as small and medium commercial customers, who receive a free Honeywell Utility Pro programmable thermostat and access to an on-line energy management system. During the months of June through September, WattSaver participants agree to allow Westar to cycle their central air conditioners or heat pumps (on and off in 15-minute intervals) in a coordinated effort to reduce energy demand during peak times. These cycling events normally last about four to six hours or less and occur between noon and 8 p.m. Cycling events occur infrequently and only on weekdays – never on weekends or holidays. In 2011, Westar implemented the program six times. Currently, more than 32,000 Westar customers are enrolled in the program, which provides an estimated 27 MW of load reduction capability. Westar anticipates enrollment of 90,000 participants by the end of 2016.[114]

The SPP RTO member, Oklahoma Gas and Electric (OG&E), installed approximately 40,000 smart meters on customer homes in Norman, Oklahoma since 2010. The information delivery infrastructure was also installed to carry data to and from the customers and OG&E. OG&E estimates that this program will provide 84 MW of Demand Response during peak hours.[115]

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[114] http://www.westarenergy.com/wcm.nsf/9696428027fd605386257735006b6631/132c71de2af99f278625791e00651ba7?OpenDocument&Highlight=0,wattsaver.

[115] http://www.ogepet.com/programs/smarthours.aspx.

In January, 2012, Kansas City Board of Public Utilities (KCBPU) started a voluntary program in which a free Honeywell UtilityPro thermostat is installed in homes. Participating customers agree to allow KCBPU to raise the temperature in their home or business by up to two degrees. This will allow KCBPU to reduce summer electricity demand during periods of peak use and extreme heat. These peak events typically last no more than four hours and begin on a weekday afternoon and end in early evening. KCBPU expects to enroll 6,000 customers that will provide a demand reduction of approximately 10 MW.[116]

Generation

For the 2012 assessment timeframe, SPP RTO forecasts 63,550 MW of Existing-Certain; 6,979 MW of Existing-Other; and 242 MW of Existing-Inoperable capacity. The primary fuel sources in the SPP RTO footprint are gas (42 percent) and coal (40 percent). Several new generation units have been added to the SPP RTO fleet since the 2011 summer assessment, including 308 MW of wind, 552 MW of gas, and 168 MW of coal. Table 96 includes projections of SPP resources for the 2011 and 2012 summer.

Table 96: SPP Resources

Resources	Summer Peak Forecast	
	2011	2012
Existing-Certain	61,395	63,547
Future-Planned	203	2
Supply-Side Demand Response	1,252	0
Net Capacity Transactions	1,899	1,309
Anticipated	**64,748**	**64,908**
Existing-Other and Future-Other	2,057	2,492
Prospective	**66,804**	**71,831**

The SPP RTO projects 2 MW of Future-Planned resources to be added between June and September 2012. Approximately 1,028 MW of new wind, natural gas, and coal generation have been added since the last reporting season. No new uprates have been reported since the 2011 summer. Approximately 242 MW of generation are expected to be taken out of service for scheduled maintenance during the 2012 summer timeframe and will not return prior to the season's end. Retirements since last summer include two natural gas units, totaling 37 MW, as well as several units derates.

No long-term maintenance outages were reported and behind-the-meter generation has been included as Existing-Other capacity.

For the 2012 summer, projected on-peak capacity from renewable resources include 99 MW of wind, 5 MW of solar, 2,019 MW of Hydro, and 8 MW of biomass. The expected on-peak capacity values for this variable generation were determined by guidelines established in the SPP Criteria Section 12.0.[117] The maximum capacity for these variable resources is 6,734 MW. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 54 and Table 97.

[116] http://www.bpu.com/AboutBPU/BPUoffersFreeUtility.aspx.
[117] Refer to the following SPP criteria: http://www.spp.org/publications/CRITERIA and Appendices 01-25-2011Current.pdf.

Figure 54: SPP Renewable Resources

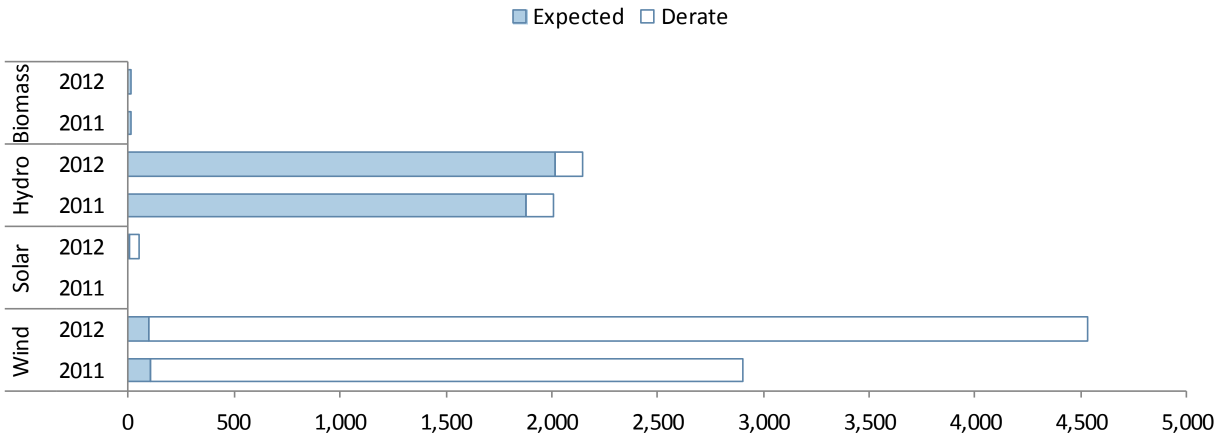


Table 97: SPP Renewable Resources

On-Peak	Summer Peak Forecasts							
	Wind		Solar		Hydro		Biomass	
	2011	2012	2011	2012	2011	2012	2011	2012
Expected	107	99	0	5	1,876	2,019	11	8
Derate	2,800	4,431	0	45	130	127	0	0
Nameplate	**2,907**	**4,530**	**0**	**50**	**2,006**	**2,146**	**11**	**8**

For the 2012 summer, SPP RTO projects less than 4 percent of the total wind capacity to be available on peak, along with a very small portion of solar. SPP RTO grid operators will continue to monitor any operating challenges for this assessment period. There are no impacts to summer operational procedures due to variable resources.

Capacity Transactions

SPP RTO members reported the following Firm contract backed imports and exports for 2012 summer in Table 98.

Table 98: SPP Capacity Transactions

Capacity Transactions	Imports	Exports	Net
Firm	2,346	1,037	1,309
Expected	50	0	50
Total	**2,396**	**1,037**	**1,359**

SPP RTO members, along with some members of the SERC Region, have formed a Reserve Sharing Group (RSG). RSG members receive contingency reserve assistance from each other; the group does not require support from generation resources outside the SPP RTO Region.[118] The SPP RTO's Operating Reliability Working Group sets the RSG's Minimum Daily Contingency Reserve Requirement. The RSG maintains a minimum first Contingency Reserve equal to the generating capacity of the largest unit scheduled to be online, plus one-half of the capacity of the next largest generating unit scheduled to be online.

[118] While the RSG does have generation-owning members outside the SPP footprint, that generation is not expected to provide support into SPP.

Transmission

Transmission projects listed in the following tables are needed to maintain or enhance reliability during the 2012 summer timeframe. The projects in Table 99 are expected to be placed in service by the end of June 2012.

Table 99: SPP Transmission Projects Expected In Service by June 2012

From Bus Name	To Bus Name	Voltage (kV)	Mileage	Category
Arcadia	Ompa-Edmond Garber (Lake)	138		Substation
Heizer	Mullergren	115	1.03	Rebuild/Re-Conductor
Holcomb	Plymell	115	11.96	Rebuild/Re-Conductor
Lone Star South	Pittsberg	138		Substation
Loup City	North Loup	115		Substation
Maloney	North Platte	115		Substation
Moore County Interchange	Hitchland Interchange	230	62	New Line
Northwest Manhattan		115		Substation
Northwest Manhattan	Northwest Manhattan	230/115		Substation
Oak Park	Jonson	161	2	New Line
Plymell	Pioneer Tap	115	14.87	Rebuild/Re-Conductor
Potter County Interchange	Potter County	230/115		Transformer, new
Powell Street	Linwood	138		Substation
Riverside Station	Okmulgee	138		Substation
Russell	Altus JCT TAP	138		Substation
Sooner	Rose Hill	345	53	New Line
South Hays	Hays Plant	115		Substation
Stilwell	Archie	161	3.6	New Line
Twin Church	South Sioux City	115	7	New Line
Weleetka	Pharoah	138		Substation
Wolfforth Interchange	Yuma Interchange	115		Substation

SPP RTO identified the projects in Table 100 as necessary to maintain or enhance reliability during the 2012 summer, but SPP RTO members indicated that construction could not be completed until the dates listed. The following construction schedules are not expected to affect reliability due to mitigation plans put in place by SPP RTO members. This includes line switching, local load shedding, and generation redispatch measures.

Table 100: SPP Transmission Projects Beyond 2012 Summer

Project Owner Indicated In-Service Date	RTO Determined Need Date	From Bus Name	To Bus Name	Voltages (kV)	Mileage	Category
9/1/2012	6/1/2012	Twin Church	South Sioux City	115	10	New Line
12/1/2012	6/1/2012	Loma Vista East	KC South	161	4	New Line
12/31/2012	6/1/2012	Easton REC	Knox Lee	138		Substation
12/31/2012	6/1/2012	Easton REC	Pirkey	138		Substation
3/31/2013	6/1/2012	Tuco Interchange	Tuco Interchange	345/230		Transformer, new
6/1/2013	6/1/2012	Atoka West	Tupelo (WFEC)	138	6.5	New Line
6/1/2013	6/1/2012	Grandfield	Indiahoma	138	3	Voltage Conversion
6/1/2013	6/1/2012	Indiahoma	Cache SW	138	13.7	New Line
6/1/2013	6/1/2012	Lynn County Interchange		115		Substation
6/1/2013	6/1/2012	Southwest Shreveport	Springridge REC	138	7.11	Rebuild/Re-Conductor
6/1/2013	6/1/2012	Tecumseh Energy Center	Midland	115	19.33	Voltage Conversion
6/1/2013	6/1/2012	Whitney	Eastex	138	2.49	Rebuild/Re-Conductor
6/1/2014	6/1/2012	Kansas Tap	W Siloam Springs	161	8.8	Rebuild/Re-Conductor
6/1/2014	6/1/2012	W Siloam Springs	Siloam City	161	4.2	Rebuild/Re-Conductor

Operations

SPP RTO operations, in conjunction with MISO, created a joint operating guide in 2011 in response to the Missouri River flood-related constraints that occurred in July 2011. This operating guide identified possible constraints for probable, moderate and extreme flood-related forced outage scenarios. If a facility contingency occurs and real-time loading on the monitored facilities exceeds applicable ratings, MISO and the SPP Reliability Coordinator will implement available mitigating and emergency actions as required.

As variable generation penetration and growth continues, further analysis will be required to mitigate any potential reliability issues. SPP RTO is currently investigating measures to integrate more wind into its footprint, such as increasing operating reserves and implementing regional variable resource forecasting. Operating procedures, such as a unit curtailment plans specific to an individual variable resource, have been and will continue to be developed when transmission constraints are identified.

Vulnerability Assessment

SPP RTO has areas within the footprint that have been experiencing long-term (>6 months) drought conditions. The areas affected have minimal hydro facilities and unit derates have not occurred at this time, since water levels for bodies of water that supply cooling water are adequate. More recently, the Region has been experiencing heavy winter and spring rain totals that are expected to relieve the drought conditions. There is no resource adequacy or operational concerns for the upcoming summer.

Since the SPP RTO has an abundant generation supply, significant long-term generator outages are not a concern. There are also no short-term concerns related to Demand Response programs, or the potential for these programs to be unresponsive or unavailable, since these programs are not relied upon for resource adequacy.

To ensure the most efficient and effective use of renewable resources, SPP's operations staff must maintain and enhance its ability to project how much wind generation will be available to reliably serve load over given time periods. Unpredictability remains the largest obstacle in effectively integrating wind energy into the SPP RTO generation mix. As wind speeds change, utilities must instantaneously switch to and from other generating resources to compensate for this variability. Increased accuracy in forecasting capabilities regarding the time, location, and speed of wind will significantly enhance the ability of the operator to reliably manage the grid. Accordingly, SPP implemented a new wind forecasting tool in 2011 to generate five-minute, hourly, and day-ahead projections.

The Acadiana Load Pocket located in southern Louisiana did not experience any reliability issues in 2011 winter or summer. The addition of the 230 kV line from Roark to Sellers road in spring 2011, along with the energizing of the Segura 230 kV line in fall 2011, alleviated a portion of the most limiting elements. The 230 kV line from Labbe to Bonin was energized in February 2012, and two other 230 kV lines from Wells to Labbe and Labbe to Sellers Rd. are expected to be energized this summer. Completion of these projects should further mitigate transmission congestion in this area and will conclude all planned Acadiana Load Pocket projects.

The SPP RTO has one Special Protection System (SPS) that was implemented in fall 2011 and is expected to be in service for three years. An automatic control system (ACS) was implemented to curtail output from a wind farm to limit the flow on the MKEC Station – Cudahay line to 90 percent of the line rating, under normal conditions. This SPS will alleviate any overloads in the event of a system contingency or the failure of the ACS system.[119] This temporary solution will be replaced with a permanent one with the construction of a second 115kV North Judson Large to Spearville line, which would eliminate the single contingency exposure to overloading the MKEC Station to Cudahay line.

The Cross-State Air Pollution Rule (CSAPR), adopted by the Environmental Protection Agency (EPA) in July 2011, called for SO_2 and annual NO_X reductions that were to begin in January 1, 2012. The SPP RTO

[119] The SPS will measure the current at the MKEC station on the Cudahay line and trip feeder breakers at the wind farm if any phase current on the Cudahay line exceeds the relay set point. In addition, the scheme will trip the 115KV transmission breaker for the wind farm tie at the MKEC station as backup if the overload persists after attempting to trip all four feeders at the wind farm.

performed a CSAPR assessment in September 2011. SPP's reliability assessment of the CSAPR Integrated Planning Model 4.1[120] generation dispatch indicated that the Rule could have serious, negative implications to reliable electric grid operation in the SPP RTO. As a result, the SPP RTO and SPP RE recommended EPA delay the effective CSAPR date for at least a year to allow adequate time for SPP RTO and its members to investigate, plan, and develop solutions for maintaining grid reliability.

In December 2011, the U.S. Court of Appeals issued a stay of CSAPR and the effective date is unknown at this time. Due to the stay, it is not expected that the CSAPR will be in effect in 2012, allowing SPP and its members the opportunity to study, plan, and possibly retrofit to support reliable operation through the 2012 summer season. The SPP RTO has conducted a reliability impact assessment based on the planning activities of members in order to comply with both the CSAPR and the Mercury and Air Toxic Standards (MATS). Based on the assessment results, the SPP RTO does not anticipate that these EPA regulations will have a reliability impact in the SPP RTO area during the 2012 summer assessment period.

The SPP RTO does not expect any generators that could impact reliability to be out of service during the 2012 summer timeframe. Regarding fuel supply issues, the SPP RTO reviews potential supply limitations by consulting with its generation-owning and generation-controlling members. There are currently no known infrastructure issues projected to impact fuel deliverability, as the SPP Region is blanketed by major pipelines and railroads that provide adequate fuel supply. SPP criteria requires coal and natural gas-fired power plants, which make up approximately 40 percent and 42 percent of total generation, respectively to maintain sufficient quantities of standby fuel on-site, in case of deliverability issues.[121]

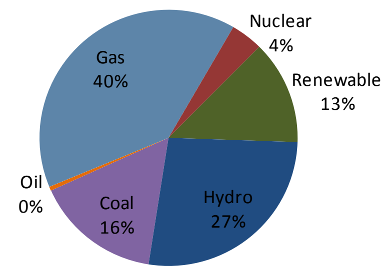
[120] Refer to the following link for additional information on the EPA CSAPR Model: http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html.

[121] Refer to SPP criteria 2.4.2: http://www.spp.org/publications/Criteria and Appendices April 25, 2011.pdf.

WECC

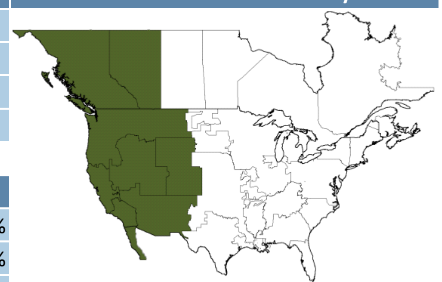
2012 Summer Peak Capacity and Reserve Margins	MW	Margin
Existing-Certain	173,855	-
Future-Planned	1,372	-
Supply-Side Demand Response	0	-
Net Capacity Transactions	0	-
Anticipated	**175,228**	**21.04%**
Existing-Other and Future-Other	0	-
Prospective	**175,228**	**21.04%**
Reference Margin Level	-	**14.60%**

On-Peak Capacity by Fuel Type



Peak Demand	2011	2012
Net Internal Demand	**144,874**	**144,766**
Demand-Side Demand Response (2012)	-	4,407
Supply-Side Demand Response (2011)	4,274	-
Total Internal	**149,148**	**149,173**

Assessment Area Boundary



2011 Summer Comparison	MW	% Change
Net Internal Demand Forecast	144,874	2.97%
Actual Peak Demand	147,299	-1.72%
All-Time Summer Peak Demand (July 24, 2006)	161,131	-10.16%

Note: Additional information regarding the methods and assumptions used in the development of the WECC seasonal assessment can be found in Appendix I and on the NERC website.[122]

Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the WECC Assessment Area and to highlight any reliability concerns associated with resources, including Generation and Transmission, or System Operations under normal weather conditions. Data was collected from individual entities, BAs, and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data. Subregional data is presented for WECC Planning Reserve Margins, demands, resources, and renewables.

For the Summer Assessment, the WECC Region is divided into four subregions; Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/Mexico (CAMX).[123] These subregions are used for two reasons. First, the subregions are structured around Reserve Sharing Groups. These groups have similar demand patterns and have similar operating practices. Second, the WECC Reliability Coordinator (RC) collects actual demand data from the Balancing Authorities (BA) within the Reserve Sharing groups. Creating the seasonal assessments using the same footprint allows for after-the-fact comparison between demand forecasts and actual demand.

It should be noted that several subregions have different boundaries used for NERC's seasonal compared to the long-term assessments. The Balancing Authority of Northern California (BANC) and the

[122] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

[123] For this 2012 summer assessment, individual sections for each WECC subregion have been replaced with a single WECC section that highlights subregional issues as necessary.

Turlock Irrigation District (TID), although physically located in California, are members of the NWPP and their demand and resources are reported in that subregion. Likewise, California's Imperial Irrigation District (IID) is a member of the SRSG with all demand and resources are reported within that subregion. This is the first summer assessment that has reflected these changes, which makes a comparison to prior year's assessments difficult.

The reserve margins for the summer-peaking WECC Assessment Area are based on Anticipated or Prospective Resources. The Anticipated Reserve Margin is projected to remain above the Reference Margin Level throughout the 2012 summer season.

Total capacity additions of 2,941 MW are expected to occur from January through September. According to the WECC demand forecast, Total Internal Demand is expected to increase to 149,173 MW from 147,299 MW for the 2011 summer. This increase equates to an annual growth rate of 1.3 percent.

The NWPP and CAISO routinely issue summer season assessments.[124,125] Also, the Arizona Corporation Commission's Website presents summer preparedness information for some in-state utilities.[126]

Planning Reserve Margins

The Anticipated and Prospective Reserve Margins for WECC and each of its four subregions are expected to exceed the Reference Margin Level. The reserve margin adequacy is largely due to the construction of power plants in anticipation of a load growth that was interrupted by the economic recession. However, it should be noted that abnormal weather conditions would result in different reserve margins and severe adverse weather conditions or unexpected equipment failure may result in localized power supply or delivery limitations. The Planning Reserve Margins for the WECC Assessment Area and subregions are included in Table 101.

[124] Northwest Power Pool Area Assessment of Reliability and Adequacy.
[125] CAISO 2012 Summer Loads and Resources Assessment.
[126] Arizona Summer Preparedness Presentations.

Table 101: WECC Reserve Margins

WECC	Reserve Margin	Summer Peak Forecast	
		2011	2012
WECC-TOTAL	Reference Margin Level	14.20%	14.60%
	Existing-Certain & Net Firm Transactions	16.72%	20.09%
	Anticipated	19.32%	21.04%
	Prospective	19.32%	21.04%
CAMX-México	Reference Margin Level	11.90%	11.86%
	Existing-Certain & Net Firm Transactions	31.37%	22.04%
	Anticipated	31.37%	22.04%
	Prospective	31.37%	22.04%
CAMX-US	Reference Margin Level	14.90%	15.13%
	Existing-Certain & Net Firm Transactions	18.20%	15.07%
	Anticipated	19.35%	15.23%
	Prospective	19.35%	15.23%
NWPP-Canada	Reference Margin Level	12.30%	12.36%
	Existing-Certain & Net Firm Transactions	15.25%	49.78%
	Anticipated	17.71%	49.95%
	Prospective	17.71%	49.95%
NWPP-US	Reference Margin Level	15.80%	15.67%
	Existing-Certain & Net Firm Transactions	20.45%	16.73%
	Anticipated	23.25%	18.39%
	Prospective	23.25%	18.39%
RMRG	Reference Margin Level	12.50%	14.70%
	Existing-Certain & Net Firm Transactions	29.98%	34.20%
	Anticipated	31.24%	37.97%
	Prospective	31.24%	37.97%
SRSG	Reference Margin Level	13.50%	13.50%
	Existing-Certain & Net Firm Transactions	30.18%	21.87%
	Anticipated	34.60%	22.49%
	Prospective	34.60%	22.49%

Demand

For the demand forecasts in this assessment, WECC requests all BAs to submit forecasts with a 50 percent probability of occurrence. These forecasts consider various factors such as population growth, economic conditions, and normalized weather so that there is a 50 percent probability of actual demand exceeding the forecast. The peak demand forecasts presented here are coincident sums of shaped hourly demands, adjusted by the 50/50 demand forecasts. WECC did not perform any quantitative analyses – on a Regional or subregional basis – to assess the variability in demand associated with variations in weather or the economic recession. All margin results used demands associated with normal weather conditions and no attempts were made to address extreme temperature changes.

The aggregate WECC 2012 summer total coincident peak demand is forecast to be 149,173 MW and is projected to occur in July. The forecast is 1.3 percent above last summer's actual peak demand of

147,299 MW, which was established under generally normal-to-slightly-warmer-than-normal temperatures and poor economic conditions in the Region. The 2012 summer coincident peak demand forecast is 0.5 percent above last summer's forecast coincident peak demand of 148,365 MW. The demand data for the WECC Assessment Area and all subregions is included in Table 102.

Table 102: WECC Demand

WECC	Demand	Summer Peak Forecast			
		2011	2012	Change (MW)	Change (%)
WECC-TOTAL	Net Internal	144,874	144,766	-108	-0.07%
	Total Internal	149,148	149,173	25	0.02%
CAMX-México	Net Internal	2,190	2,264	74	3.38%
	Total Internal	2,190	2,264	74	3.38%
CAMX-US	Net Internal	55,442	47,279	-8,163	-14.72%
	Total Internal	57,646	49,490	-8,156	-14.15%
NWPP-Canada	Net Internal	18,013	17,757	-256	-1.42%
	Total Internal	18,035	17,769	-266	-1.47%
NWPP-US	Net Internal	36,438	41,523	5,085	13.95%
	Total Internal	35,182	41,523	6,341	18.02%
RMRG	Net Internal	10,973	10,056	-917	-8.36%
	Total Internal	10,565	10,503	-62	-0.59%
SRSG	Net Internal	28,600	28,890	290	1.01%
	Total Internal	29,049	29,402	353	1.22%

Over the past decade, peak demand and energy load growth rates have been inconsistent across WECC and within the WECC subregions. Those inconsistencies are of no particular consequence for a seasonal assessment and will be addressed in the WECC section of the NERC *2012 Long-Term Reliability Assessment*.

Demand-Side Management

Demand-Side Management (DSM) programs offered by Load-Serving Entities (LSE) vary widely. The 2012 demand forecast includes 1,662 MW of Direct Control Load Management (DCLM),[127] 1,741 MW of Contractually Interruptible Demand,[128] 2 MW of Critical-Peak-Pricing with Control, and 1,002 MW of Load as a Capacity Resource. As a percent of Total Internal Demand, total demand response could reduce peak demand by almost 3 percent. In some situations, these programs may be activated by LSEs during high power cost periods but, in general, the programs are only activated during periods when local power supply issues arise. Each LSE is responsible for verifying the accuracy of its DSM and energy efficiency programs. Methods for verification include direct end-use metering, sample end-use metering, and baseline comparisons of metered demand and usage.

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[127] Direct control-load-management programs largely focus on air conditioner cycling programs.

[128] Interruptible-demand programs focus primarily on large water-pumping operations and large industrial operations such as mining.

Energy efficiency programs vary by location and are generally offered by the LSE. Programs include: Energy Star builder incentives, business lighting rebates, retail compact fluorescent light bulbs (CFLs), home efficiency assistances, and programs to identify and develop ways to streamline energy use in agriculture, manufacturing, water systems, etc.

State and other regulatory drivers have led to nominal increases in DSM program penetration within the WECC subregions and, within some established market structures, DSM has been established as an ancillary service.

Generation

In prior seasonal assessments, WECC has reported capacity in the Existing-Other category. However, to ensure consistency between the long-term and the seasonal assessments, WECC will not report Existing-Other capacity. WECC's modeling data[129] for the Western Interconnection included the following:

- Existing-Certain: 173,855 MW
    - Hydroelectric: 30.1%
    - Coal: 17.1%
    - Natural gas: 39.7%
    - Nuclear: 4.3%
    - Other: 8.8%
- Existing-Other: 0 MW
- Existing-Inoperable: 10,643 MW

Additional capacity build from the start of the year through the end of September are classified as Future-Planned and total 2,941 MW. WECC resource projections for the 2011 and 2012 summer are included in Table 103.

[129] The modeling data for renewable resources reflect capacities as of the forecasted December 2011 peak; modeling data for other resources reflect a 2011 year-end in service date.

Table 103: WECC Resources

WECC	Resources	Summer Peak Forecast	
		2011	2012
WECC-TOTAL	Existing-Certain	169,817	173,855
	Future-Planned	3,870	1,372
	Supply-Side Demand Response	4,274	0
	Net Capacity Transactions	0	0
	Anticipated	**177,961**	**175,228**
	Existing-Other and Future-Other	0	0
	Prospective	**177,961**	**175,228**
CAMX-México	Existing-Certain	2,846	2,523
	Future-Planned	0	0
	Supply-Side Demand Response	0	0
	Net Capacity Transactions	31	240
	Anticipated	**2,877**	**2,763**
	Existing-Other and Future-Other	0	0
	Prospective	**2,877**	**2,763**
CAMX-US	Existing-Certain	50,241	40,402
	Future-Planned	664	76
	Supply-Side Demand Response	2,204	0
	Net Capacity Transactions	15,691	14,000
	Anticipated	**68,800**	**54,478**
	Existing-Other and Future-Other	0	0
	Prospective	**68,800**	**54,478**
NWPP-Canada	Existing-Certain	22,663	26,597
	Future-Planned	689	30
	Supply-Side Demand Response	22	0
	Net Capacity Transactions	1,900	0
	Anticipated	**25,274**	**26,627**
	Existing-Other and Future-Other	0	0
	Prospective	**25,274**	**26,627**
NWPP-US	Existing-Certain	47,586	48,276
	Future-Planned	296	670
	Supply-Side Demand Response	1,256	0
	Net Capacity Transactions	-4,953	-1,238
	Anticipated	**44,185**	**47,708**
	Existing-Other and Future-Other	0	0
	Prospective	**44,185**	**47,708**
RMRG	Existing-Certain	14,075	13,996
	Future-Planned	771	380
	Supply-Side Demand Response	408	0
	Net Capacity Transactions	-220	-501
	Anticipated	**15,034**	**13,875**
	Existing-Other and Future-Other	0	0
	Prospective	**15,034**	**13,875**
SRSG	Existing-Certain	40,962	41,856
	Future-Planned	1,284	180
	Supply-Side Demand Response	449	0
	Net Capacity Transactions	-3,595	-6,648
	Anticipated	**39,100**	**35,388**
	Existing-Other and Future-Other	0	0
	Prospective	**39,100**	**35,388**

WECC's modeling for the 2011 summer assessment peak period gives a total renewable expected capacity of 48,485 MW from a nameplate capacity of 82,846 MW.[130] The breakdown of these capacities by resource type is presented in the Table 104.

Table 104: WECC Renewable Generation

WECC	On-Peak	Summer Peak Forecasts							
		Wind		Solar		Hydro		Biomass	
		2011	2012	2011	2012	2011	2012	2011	2012
WECC-TOTAL	Expected	721	2,535	719	850	41,157	44,052	1,107	1,048
	Derate	14,105	10,582	70	393	15,377	22,550	372	836
	Nameplate	**14,826**	**13,117**	**789**	**1,243**	**56,534**	**66,602**	**1,479**	**1,884**
CAMX-México	Expected	8	1	0	0	0	0	0	0
	Derate	2	9	0	0	0	0	0	0
	Nameplate	**10**	**10**	**0**	**0**	**0**	**0**	**0**	**0**
CAMX-US	Expected	51	402	499	377	4,415	1,849	469	625
	Derate	2,718	988	20	166	4,119	7,722	2	131
	Nameplate	**2,769**	**1,389**	**519**	**544**	**8,534**	**9,571**	**471**	**756**
NWPP-Canada	Expected	67	511	0	0	12,432	13,929	418	191
	Derate	1,020	425	0	0	1,973	1	79	294
	Nameplate	**1,087**	**936**	**0**	**0**	**14,405**	**13,930**	**497**	**485**
NWPP-US	Expected	1,263	1,389	0	36	25,084	25,708	342	105
	Derate	7,093	6,789	0	12	6,685	11,193	23	405
	Nameplate	**8,356**	**8,177**	**0**	**48**	**31,769**	**36,901**	**365**	**510**
RMRG	Expected	66	42	4	61	851	1,109	9	1
	Derate	1,954	1,838	4	23	805	815	0	7
	Nameplate	**2,020**	**1,880**	**8**	**84**	**1,656**	**1,924**	**9**	**8**
SRSG	Expected	25	5	175	384	2,730	1,453	62	45
	Derate	559	719	70	183	957	2,794	50	51
	Nameplate	**584**	**724**	**245**	**568**	**3,687**	**4,247**	**112**	**95**

The highly variable nature of wind and solar resources complicates daily power grid operation, often more significantly during off-peak periods than during on-peak periods. Operational procedures, such as implementing and testing resource curtailment capability and increased reserve requirements, are expected to address the wind and solar generation variability issues. Operational procedures, generally involving implementing and testing resource curtailment capability and increased reserve requirements, are expected to adequately address the wind and solar generation variability issues.

Capacity Transactions

The WECC Region does not rely on imports from outside the Region when calculating peak demand reliability margins, or on outside assistance or external resources for emergency imports. WECC does

[130] The renewable expected capacity modeling for wind resources uses generation curves created from three years' of one-hour interval wind speed data. Expected Capacity modeling for solar resources uses generation curves created from two years of insolation data. Hydro generation is dispatched economically, limited by expected annual energy generated during an adverse hydro year. Biomass and geothermal capacities are based on nominal plant ratings.

not model exports to areas outside of WECC and does not model subregional purchase (sale) contracts or associated transmission. Only transfers from remotely-owned, large thermal and hydroelectric units (resources located outside the owners subregion) are allocated to the owner's subregion. All other transfers are modeled as theoretical transfers that could happen, but do not have actual contracts. This modeling treatment ensures that each resource is counted only once.

Transmission

No project delays or temporary service outages for transmission facilities have been reported that will adversely impact reliability during the 2012 summer period and no specific projects have been reported that are needed to maintain reliability. Accelerating the completion of Barre-Ellis and Sunrise Powerlink transmission projects are noteworthy projects that would help alleviate transmission constraints in Southern California.

Operations

WECC staff does not perform special operating studies concerning extreme weather or drought conditions for the seasonal assessments. However, these studies are performed by the individual Load-Serving Entities (LSE), and BAs within WECC, and there have been no reports of extreme weather or drought-related issues.

The California Independent System Operator (CAISO) has developed and employed a procedure to address an over-generation situation. When minimum demand and over generation becomes an issue due to the integration of variable resources, the procedure allows for the following actions:

- Use of decremental market bids to reduce the amount of over generation;
- Request generating units and pump loads to operate at their dispatch operating targets
- Offer energy for sale to other BAs
- Instruct generating units to reduce generation or imports on pro-rata basis to meet mitigation targets
- Issue mandatory dispatch instructions to specific generating units or external imports

The introduction of formalized operating procedures by the CAISO and other BAs has directly addressed the issue of over generation during minimum demand periods; therefore, over generation is not currently an operational concern within the Western Interconnection. While over generation may be addressed through various resource curtailment approaches, none of these approaches are without associated costs to either or both the generation owners and the consumers.

As discussed previously, LSEs within the Region have implemented demand response programs and intend to activate these programs when warranted by local operating conditions. These programs are generally geared toward activation on either short notice, or in many cases, no notice, and are often a final step before the interruption of Firm service to customers.

Power plants operate under numerous environmental and other regulatory restrictions, including emission, water level, and water temperature limitations. The cumulative magnitude of the restrictions, although not quantified, is incorporated into the expected on-peak capacities used for this assessment. These restrictions are not expected to adversely affect reliability during the summer period.

The CAISO has reported a West Sacramento Special Protection System (SPS) as a permanent solution to a double-circuit line outage and two SPSs that are temporary bulk power transmission facility solutions for thermal overloads.

Vulnerability Assessment

The West experienced a relatively warm and dry 2011/2012 winter, resulting in sparse snow pack in some areas. Runoff forecasts for California basins are one-third or less of normal conditions, while the Colorado River Basin is in the twelfth year of a persistent drought. However, a March Columbia River flow forecast was at 93 percent of the 30-year average flow, measured at The Dalles, Oregon. It is expected that the reduced river flows will result in increased thermal-based energy generation, but will not significantly impact the ability to meet peak demand. The margin information and assumptions presented in this assessment reflects adverse hydroelectric generation condition.

WECC entities have not reported any pending environmental regulations that would have an impact on their upcoming season planning and, consequently, have not included potential environmental regulation effects in their upcoming season plans.

The 2,250 MW San Onofre plant in southern California has experienced premature wear in the steam tubes for both of the plant's units and they have been shut down for repairs. The planning reserve margins for California are projected to be quite tight for the summer season and should the plant fail to return to service prior to a heat wave, emergency load shedding could be implemented in the San Diego and Los Angeles Basin portions of California. Officials are developing a plan to encourage local conservation. In addition, the CAISO has procured capacity from the Huntington Beach Unit 2 and is exploring other mitigation measures that can be put in place quickly should the plant not return to service this summer.

In additions to the San Onofre issue previously discussed, a 900 MW Intermountain Generating Station unit that provides power to the Los Angeles Basin has been forced out of service since late December. The unit is currently undergoing repairs, and it is expected that the unit will return to service by June 1, 2012. Area entities have not reported other long-term maintenance outages as a concern relative to off-peak reliability.

WECC entities also reported routine coordination of fuel supply needs with fuel and transportation suppliers on several levels. For example, significant portions of the coal supply are acquired under long-term contracts with mines and transportation providers, and the power plants generally have significant on-site coal storage facilities. These long-term arrangements are largely unaffected by short-term conditions such that seasonal planning coordination beyond pre-established parameters is minimal. Alternatively, natural gas deliveries are often scheduled on a shorter-term basis – often daily. This short-term acquisition process, coupled with (generally) very limited storage located near power plants and gas pipeline pressure limitations, may lead to supply interruptions if other conditions, such as an unexpected cold snap or colder-than-expected temperatures occur. These temperature-driven supply interruption events are typically limited to the winter and are not expected to affect reliability this summer.

On September 8, 2011, customers in Baja California, Mexico, southern California's Imperial, Orange and San Diego counties, and a small portion of southwestern Arizona experienced a major power outage. Several entities within WECC have taken, or are in the process of taking actions to prevent similar disturbances in the future. These actions include the implementation of additional real-time data exchange and coordination with additional entities in the Southwest. These processes will help facilitate a more detailed monitoring capability of neighboring systems in their energy management systems and real-time contingency analysis applications. In addition, the WECC RC has coordinated the development of an interim monitoring procedure of the San Diego and Imperial Valley areas with specific actions that will be taken for overload conditions. Additional information is now available in the joint FERC and NERC report released in April 2012.[131]

[131] http://www.nerc.com/fileUploads/File/News/AZOutage_Report_01MAY12.pdf.

Appendix I: About this Report

About This Report

The *2012 Summer Reliability Assessment* provides an independent view of the seasonal reliability for the North American bulk power system,[132] while identifying trends, emerging issues, and potential concerns. Additional insight will be offered regarding seasonal resource adequacy and operating reliability, and an overview of projected electricity demand growth, and assessment area self-assessments.

NERC's primary objective in providing this assessment is to identify seasonal reliability concerns on the North American bulk power system and to offer recommendations to address these issues. Additionally, NERC's seasonal assessments provide a platform for system users, owners, and operators to systematically document planning procedures, identify vulnerabilities, and exchange critical information for the impending season.

Assessment Preparation

This assessment is prepared by NERC in its capacity as the Electric Reliability Organization.[133] NERC cannot order construction of generation or transmission or adopt enforceable standards having that effect, as that authority is explicitly withheld by Section 215 of the U.S. Federal Power Act and similar restrictions in Canada.[134] In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets.

This report was developed by NERC in its capacity as the Electric Reliability Organization (ERO). The assessment area sections were developed by the Reliability Assessment Subcommittee (RAS), which is under the direction of the NERC Planning Committee (PC). The data and information presented in this assessment was submitted by each of the eight Regional Entities on an Assessment-Area basis. Additional data was incorporated by NERC staff with sources provided when applicable.

2012 Assessment Enhancements

Assessment Structure

In prior NERC assessments, seasonal and long-term projections were presented in a single document that included information about the methods and assumptions (*i.e.*, load modeling) employed by each assessment area to arrive at these projections. Although the outlook changes from season to season, the methods and assumptions used by each assessment area are more permanent. Accordingly, NERC assessments will be provided in two parts:

- Part I: Seasonal Outlook
- Part II: Assessment Methods and Assumptions

[132] Bulk power system reliability, as defined in the *How NERC Defines Bulk Power System Reliability* section of this report, does not include the reliability of the lower voltage distribution systems, which systems account for 80 percent of all electricity supply interruptions to end-use customers.

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

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

The information included in Part II will ultimately be provided on the NERC website, eliminating the need for a separate report. Detailed information for each assessment area will be posted through an online portal, reflecting the most up-to-date load-forecasting, resource adequacy studies, and other critical information used in the development of seasonal and long-term projections.

Assessment areas are subjected to scrutiny and review by the entire Reliability Assessment Subcommittee (RAS). This review ensures that RAS members fully convinced that each assessment area provides an accurate and complete assessment of seasonal and long-term reliability. Data is further reviewed to ensure that transfers into or between two areas are validated.

The NERC Planning Committee endorses this report prior to being sent to the NERC Board of Trustees (BOT) for approval. The draft, endorsed by the Planning Committee includes comments received from representatives on the NERC Operating Committee and the Member Representative Committee (MRC). Drafts of the document are considered confidential and embargoed until approval is received from the NERC BOT.

In the *2012 Summer Reliability Assessment* baseline information on future electricity supply and demand is based on several assumptions:[135]

- Supply and demand projections are based on industry forecasts submitted in May 2012. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data may be submitted throughout the drafting timeframe (May – September).
- Peak demand and Planning Reserve Margins are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Region's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in-service as planned; planned outages take place as scheduled; retirements are scheduled as proposed
- Demand reductions expected from dispatchable and controllable Demand Response programs will yield the forecast results, if they are called on.
- Other peak Demand-Side Management programs, such as Energy Efficiency and price-responsive Demand Response, are reflected in the forecasts of Total Internal Demand.

Updated Demand Response Concepts and Categorization

The continued saturation of Demand Response highlights the need for NERC's reliability assessments to accurately reflect how these resources are treated in each assessment area. Demand Response programs offer different functionality that ultimately depends on how each program is used by the respective Balancing Authority. While some Demand Response programs are considered supply-side resources, others are considered as demand-side resources, or load modifiers. In 2010, the NERC

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

Resource Issues Subcommittee (RIS) released several recommendations[136] to address the treatment of Controllable Capacity Demand Response (CCDR) in future NERC reliability assessments. Most importantly, all CCDR were to be considered supply-side resources.

Attempts to impellent a uniform approach presented unforeseen complications in NERC's 2011 reliability assessments. While certain assessment areas internally modeled CCDR as a load-modifier in their Loss-of-Load Expectation (LOLE) studies, NERC was collecting and presenting CCDR exclusively as a supply-side resource. The most critical impact was reflected in a misrepresentation of the assessment area's reserve margins.

The Reliability Assessment Subcommittee (RAS) revisited this issue in early 2012 and provided new recommendations for the treatment of Demand Response. Assessment areas were asked to report Demand Response based on how it is modeled within their respective LOLE studies. Ultimately, Demand Response should be considered as a demand-side resource, only if the assessment area does not carry reserves for this curtailable demand during the peak.

Updated Reserve Margin Calculations

The modifications to the collection and presentation of CCDR have required additional modifications to the Planning Reserve Margin Calculations. The pre-2010 calculation, 2011 calculation and 2012 calculations are presented in Table I-1.

Table I-1: Reserve Margin Calculations

Pre-2011	$RM = \frac{[\text{Capacity} + CCDR_{TOTAL}] - [\text{Total Internal Demand} - CCDR_{TOTAL}]}{[\text{Total Internal Demand} - CCDR_{TOTAL}]}$	$\rightarrow$	$RM = \frac{[\text{Capacity} + CCDR_{TOTAL}] - [\text{Net Internal Demand}]}{[\text{Net Internal Demand}]}$
2011	$RM = \frac{[\text{Capacity} + CCDR_{SUPPLY}] - \text{Total Internal Demand}}{\text{Total Internal Demand}}$	$\rightarrow$	$RM = \frac{[\text{Capacity} + CCDR_{SUPPLY}] - \text{Total Internal Demand}}{\text{Total Internal Demand}}$
2012	$RM = \frac{[\text{Capacity} + CCDR_{SUPPLY}] - [\text{Total Internal Demand} - CCDR_{DEMAND}]}{[\text{Total Internal Demand} - CCDR_{DEMAND}]}$	$\rightarrow$	$RM = \frac{[\text{Capacity} + CCDR_{SUPPLY}] - [\text{Net Internal Demand}]}{[\text{Net Internal Demand}]}$

Total Internal Demand — 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 (forecast). Total Internal Demand includes adjustments for the indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electricity use, and all non-dispatchable Demand Response Programs. This value is used in the Planning Reserve Margin calculation.

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

NERC Assessment Areas

Prior to the release of the *2011 Summer Reliability Assessment*, NERC had presented assessment data and information based on Regional Entity boundaries. These boundaries were established through consideration of the respective membership of each Regional Entity, comprising of both Planning Coordinators and Load Serving Entities (LSEs). There are approximately eighty NERC Planning

[136] Recommendations for the Treatment of Controllable Capacity Demand Response Programs in Reserve Margin Calculations: http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf.

Coordinators, ten of which are Independent System Operators (ISOs) and/or Regional Transmission Organizations (RTOs) which encompass a large portion of North America. Four of these Planning Coordinators operate in multiple Regional Entities listed below:

- American Transmission Co., LLC: MRO, RFC
- Midwest Independent Transmission System Operator, Inc: MRO, RFC, SERC
- PJM Interconnection, LLC: RFC, SERC
- Southwest Power Pool: MRO, SPP

Historically, these four Planning Coordinators have provided capacity and load data to multiple Regional Entities. Consequently, this data has been artificially divided based on political boundaries that failed to accurately reflect the planning and operational properties of the bulk power system. This approach has reduced the accuracy of the resource and demand balance in these four Planning Coordinators that span over multiple Regional Entity boundaries. Taking these considerations into account, NERC instituted the following assessment areas presented in Figure I-1 in the *2011 Summer Reliability Assessment*.

Figure I-1: 2012 Seasonal assessment areas[137]

It is important to note that ISO/RTO boundaries are subject to change over time, due to consolidation of Load Serving Entities (LSE) and/or alterations in resource planning and acquisition arrangements. NERC's assessment areas will adjust accordingly and any potential changes will be identified in future reliability assessments.

The term "assessment area" has been applied consistently throughout this reliability assessment. However, the terms "Region," or "subregion" may also be used when the assessment area boundaries are synonymous to the Regional Entity or subregional boundaries.[138]

[137] For NERC's seasonal reliability assessments, WECC is divided into four subregions: Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/México (CAMX). These seasonal subregions are structured around WECC's Reserve Sharing groups that experience similar demand patterns and employ similar operating practices. Additionally, the Western Reliability Coordination Offices collect actual demand data from the Reserve Sharing groups and leveraging the same footprints allows for consistent comparisons between demand forecasts and actual demands. NERC further divides the CAMX and NWPP subregions to provide additional data granularity for Canada, and México. For additional information, refer to the WECC section.

[138] For example, the ERCOT assessment area is synonymous to the ERCOT ISO and TRE Regional Entity, however, there is a PJM assessment area, but no PJM region within this assessment.

Appendix II: Estimated Demand, Resources, and Reserve Margins

Demand

NERC uses the following terms to categorize on-peak electricity demand:

- **Total Internal Demand**: 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 (forecast). Total Internal Demand includes adjustments for the indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electricity use, and all non-dispatchable Demand Response Programs. This value is used in the Planning Reserve Margin calculation.
- **Net Internal Demand**: Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce peak load.

Capacity Resources

NERC uses the following terms to categorize capacity resources and transactions in seasonal assessments:

Existing Capacity Resources

- **Existing-Certain**: Existing generation resources available to operate and deliver power within or into the assessment area (or Region) during the period of assessment.
- **Existing-Other**: Existing generation resources that may be available to operate and deliver power within or into the assessment area (or subregion/Region) during the period of assessment, but may be curtailed or interrupted at any time for various reasons.
- **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 assessment.

Existing Capacity Resources

- **Future-Planned**: Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of assessment.
- **Future-Other**: Future generating resources that do not qualify in Future-Planned and are not included in the Conceptual category.

Capacity Transactions

- **Net Firm and Expected Transactions**: Firm and Expected Imports, minus Firm and Expected Exports; including all Firm contracts with a reasonable expectation to be implemented.

Reserve Margins

Reserve Margins are capacity-based metrics and do 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). Each capacity resource category (identified and explained in the previous section) is also used to calculate each different planning Reserve Margin.

Planning Reserve Margins for each assessment area are compared to the NERC Reference Margin Level, which is assigned for each NERC assessment area as defined and imposed by the corresponding Regional Entity, State Public Utility Commission, Provincial authority, or other delegating body. In the absence of a defined Reference Margin, NERC has applied 10 or 15 percent Reference Margin Levels for predominately hydro or thermal systems, respectively.

The NERC Reference Margin Level serves as a basis for determining whether more resources (*e.g.,* generation, Demand-Side Management, capacity transfers) may be needed within that Assessment Area.

Note 1: Demand and Supply forecasts were reported between February and August, 2011—depending on the assessment area.

Note 2: Values for both Total Internal Demand and Net Internal Demand for each assessment area represent on-peak projections.

Note 3: The WECC-US peak demands or resources do not necessarily equal the sums of the non-coincident WECC-US subregional peak demands or resources because of subregional monthly peak demand diversity. Similarly, the Western Interconnection peak demands or resources do not necessarily equal the sums of the non-coincident WECC-U.S., Canada, and México peak demands or resources. In addition, the subregional resource numbers include use of seasonal demand diversity between the winter-peaking northwest and the summer-peaking portions of the Western Interconnection.

Appendix III: 2012 Summer Reliability Assessment Data and Information Request

The data request letter provided to the Regional Executives in January 2012 included the following instructions:

2012 Summer Reliability Assessment - Letter to Regional Entity Executives
http://www.nerc.com/docs/pc/ras/2012%20Summer%20Reliability%20Assessment%20Request%20Letter.doc

2012 Summer Reliability Assessment - Data Form
http://www.nerc.com/docs/pc/ras/ERO2012_SA_v4.xls

Appendix IV: Reliability Concepts Used in this Report

How NERC Defines Bulk Power System Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:[139]

- **Adequacy** — is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
- **Operating Reliability** — is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

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

- Public appeals.
- Interruptible demand — demand that the end-use customer makes available to its LSE via contract or agreement for curtailment.[140]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5 percent).
- Rotating blackouts — the term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders.

Under the heading of Operating Reliability, are all other system disturbances that result in the unplanned and/or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as "cascading blackouts" – the uncontrolled successive loss of system elements triggered by an incident at any location.

Planning Reserve Margin

The Planning Reserve Margin is a key metric that measures the flexibility to meeting customer demands and to handle the loss of one or more system elements as well as unforeseen, higher than expected demands. Specifically, the Planning Reserve Margin is the difference between the total resource capacity (which includes all generation physically available to provide deliverable power to load, transfers from neighboring area, and demand response resources designated as a supply-side resource) and system peak demand. It is the fraction of capacity available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen, higher than expected demands.

[139] Additional information regarding the Adequate Level of Reliability (ALR): http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

[140] Interruptible Demand (or Interruptible Load) is a term used in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, February 12, 2008, at http://www.nerc.com/files/Glossary_12Feb08.pdf.

Planning Reserve Margins are needed because a dependable supply of electricity is essential to the health, safety, and economic well-being of customers. Because electricity cannon be stored and must be produced at the instant it is used, there must always be some margin to allow for the repair and maintenance of equipment and the unavailability of resources.

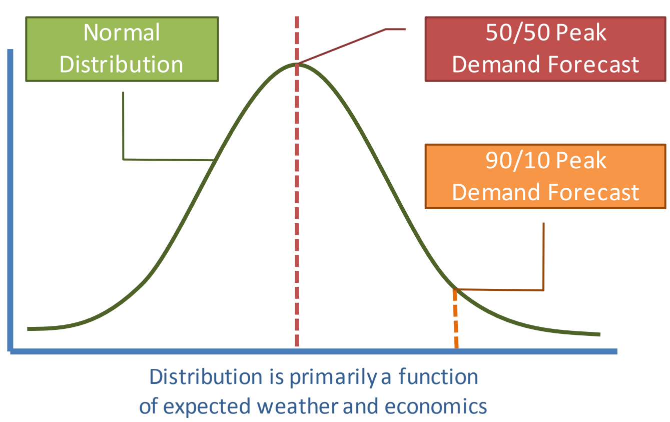
Planning Reserve Margins differ from Operating Reserve Margins in that Operating Reserve Margins are based on day-ahead and real-time system needs. Operating Reserve Margins, much like a shock absorber, are needed so that the electric system can respond and rebalance when sudden failures of equipment or sudden increases in customer demand occur. This type of margin must be instantly available so the electric system can remain in dynamic balance. Operating Reserves include such products as contingency reserves, spinning and non-spinning reserves, and regulation. Operating Reserve Margins also provide flexibility in operations, which allows the system operator to use the most economical plants to serve customer demand reducing fuel and operating costs.

How Margins are Assessed

Proper planning, construction and operating of the system according to well established standards and guidelines assure adequate Planning and Operating Reserve Margins. Adequate Planning Reserve Margins depend on future electricity demands, completion of new generation and transmission facilities, retirement of generation, and performance of existing facilities. Assuring sufficient Planning Reserve Margins starts with a forecast of the future electricity requirements of residential, commercial, industrial, and governmental customers for up to 10 years or more in the future. Demand forecasts are continually reviewed and updated as economic conditions and other factors change.

For NERC reliability assessments, aggregated load forecasts are a single number or point; that is, the peak load or energy requirements for a given year are reported as a single specific value. In actuality, any forecast in itself is not a point or single value, but a probability distribution. The specific value represented in the assessment represents the probabilistic midpoint of the distribution such that the likelihood of exceeding it is equal to the likelihood of it not being reached (*i.e.*, a 50/50 forecast). While this has been understood within the industry, increasing interest in and attention to load forecasts by non-industry groups has led to frequent misunderstanding of the forecasts.

Table IV-1: Example Load Forecast Distribution



Furthermore, point or single value forecasts imply a greater degree of precision and certainty than is appropriate. The load or load growth actually experienced is a function of many factors over which the electric power industry has little or no control – including the performance of local and national economies, the price of electricity, domestic versus foreign production of goods and services, industrial and other policies, changing technologies, federal and state legislation, and weather,. These and many other factors greatly influence the actual peak loads and energy requirements and make deviation from forecast values a common occurrence. In addition, comparing actual loads to point forecasts may be misleading since it does not appropriately express the wide variation of causative factors involved.

Both demand and supply forecasts are subject to uncertainties and risks. Changes in future economic growth can affect demand forecasts and supply forecasts can change if new facilities are delayed, postponed, or cancelled. Generation retirement uncertainties also exist in the supply forecast.

Uncertainty and risks are significant and must be factored into the planning process. Planning Reserve Margins provide the flexibility to mitigate and lower potential risks and uncertainties. The best way to deal with the risks and uncertainties in to increase flexibility by shortening lead-times to site, license, and construct facilities, and to keep open all supply and demand options for the future.

Upon calculating Planning Reserve Margins, a comparison to the NERC Reference Margin Level is made. Planning Reserve Margins for each assessment area are compared to the NERC Reference Margin Level, which is assigned for each NERC assessment area as defined and imposed by the corresponding Regional Entity, State Public Utility Commission, Provincial authority, or other delegating body. In the absence of a defined Reference Margin Level, NERC has applied either a 10 or 15 percent Reference Margin Level for predominately hydro or thermal systems, respectively. There are no NERC Reliability Standards which mandate maintaining a certain level of Planning Reserves. There is also no one appropriate margin for each utility, power pool, ISO/RTO, or Region. Operating conditions tend to be quite different because of such things as: changing weather conditions, characteristics of generation and transmission facilities, varying economic conditions, and custom demand patterns. Additionally, Planning Reserve Margins are not comparable across the difference assessment area.

Developing Planning Reserve Margin Targets

As bulk power system planning has become increasingly complex, analytical techniques developed to assess resource adequacy have also become increasingly complex. Common to most methods is a sophisticated application of probability theory. Most techniques require assumptions which also derive from probability theory. For example, an estimate must be made of the probability that generating units modeled will be available when called upon to serve. Historical forced outages rates are used to forecast future rates, but obviously such an assumption is uncertain and the likelihood of higher or lower rates is inherent in the estimate.

Perhaps the most widely recognized index of reliability is Loss of Load Expectation (LOLE), also known as Loss of Load Probability (LOLP), which is ordinarily measured in days per year. These probabilistic values can then be used to determine what level of Planning Reserve Margin is needed in order to meet a “1 day in 10” loss of load. Like generation and demand distributions, the LOLE is also a distribution. The ability to serve load without Firm load interruption for every peak hour for ten years, except for one, is an industry-accepted, non-binding planning guideline. The resulting Planning Reserve Margin target is one that is probabilistically associated with the “1 day in 10” loss of load expectation (*i.e.*, LOLE = 0.1).

For some assessment areas, the methods are not as complex. For example, the FRCC Planning Reserve Margin target (NERC Reference Margin Level, is based a state-mandated flat percentage. For others, a target is applied based on generally accepted level using historical performance and engineering judgment.

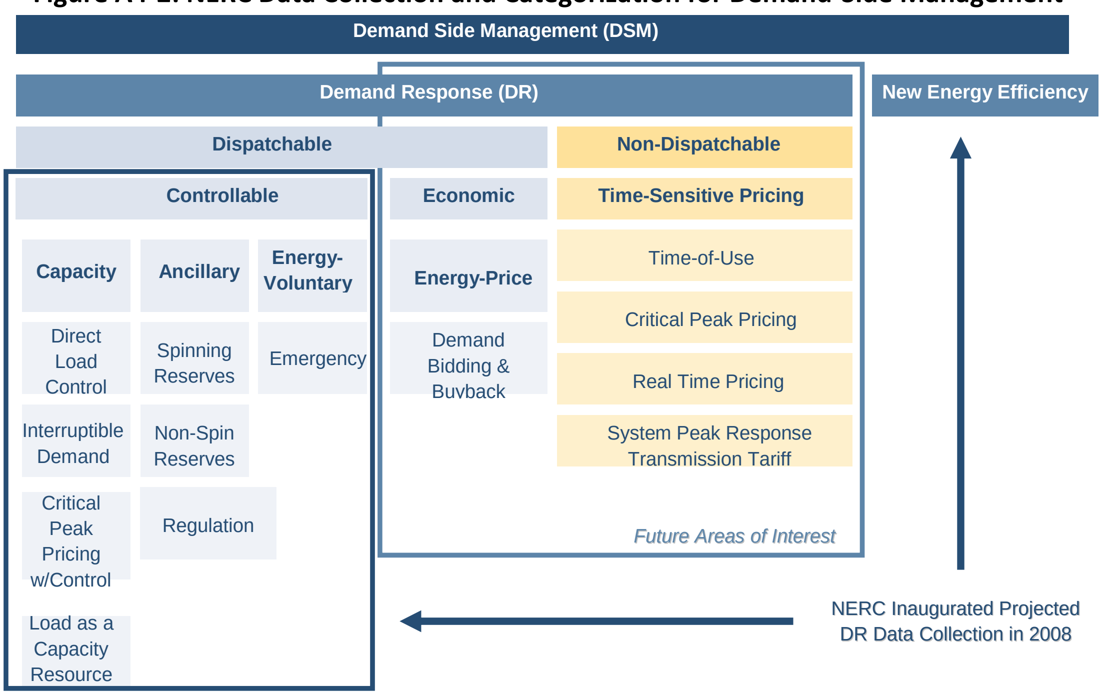
Demand Response Concepts and Categorization

As the industry's use of Demand-Side Management (DSM) evolves, NERC's data collection and reliability assessments need to change highlighting programs and demand-side service offerings that have an impact on bulk system reliability.

NERC's seasonal and long-term reliability assessments currently assume projected Energy Efficiency programs are included in the Total Internal Demand forecasts, including adjustments for utility indirect Demand Response programs such as Conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. DSM involves all activities or programs undertaken to influence the amount and timing of electricity use

Note the context of these activities and programs is DSM, rather than bulk power systems and, therefore, they are not meant to mirror those used in the system context. Figure A4-2 explains Demand Response categories are further defined in *Terms Used in this Report*.

Figure A4-2: NERC Data Collection and Categorization for Demand-Side Management



Appendix V: Terms Used in this Report

Ancillary (Controllable Demand Response) — Demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance.

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

Anticipated Reserve Margin (%) — Deliverable Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

Capacity (Controllable Demand Response) — Demand-side resource displaces or augments generation for planning and/or operating resource adequacy; penalties are assessed for nonperformance.

Capacity Categories — *See* ***Existing Generation Resources, Future Generation Resources,*** *and* ***Conceptual Generation Resources***.

Capacity Margin (%) — *See* ***Deliverable Capacity Margin (%)*** *and* ***Prospective Capacity Margin (%)***. Roughly, Capacity minus Demand, divided by Capacity or (Capacity-Demand)/Capacity. Replaced in 2009 with *Reserve Margin(s) (%)* for NERC Assessments.

Conceptual **Generation Resources** — This category includes generation resources that are not included in *Existing Generation Resources* or *Future Generation Resources*, but have been identified and/or announced on a resource planning basis through one or more of the following sources:

- Corporate announcement
- Entered into or is in the early stages of an approval process
- Is in a generator interconnection (or other) queue for study
- "Place-holder" generation for use in modeling, such as generator modeling needed to support NERC Standard TPL analysis, as well as, integrated resource planning resource studies.

Resources included in this category may be adjusted using a confidence factor (%) to reflect uncertainties associated with siting, project development or queue position.

Conservation — *See* ***Energy Conservation***

Contractually Interruptible (Curtailable) (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-side management achieved by a customer reducing its load upon notification from a control center. The interruption must be mandatory at times of system emergency. Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Entity's seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Controllable (Demand Response) — Dispatchable Demand Response, demand-side resources used to supplement generation resources resolving system and/or local capacity constraints.

Critical Peak Pricing (CPP) (Non-dispatchable Time-Sensitive Pricing Demand Response) — Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours.

Critical Peak Pricing (CPP) with Control (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-side management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Curtailable — *See* ***Contractually Interruptible***

Demand — *See* ***Net Internal Demand, Total Internal Demand***

Demand Bidding & Buyback (Controllable Energy-Price Demand Response) — Demand-side resource that enable large consumers to offer specific bid or posted prices for specified load reductions. Customers stay at fixed rates, but receive higher payments for load reductions when the wholesale prices are high.

Demand Response — Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Derate (Capacity) — The amount of capacity that is expected to be unavailable on seasonal peak.

Direct Control Load Management (DCLM) or Direct Load Control (DLC) (Controllable Capacity Demand Response) — Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.[141]

Dispatchable (Demand Response) — Demand-side resource curtails according to instruction from a control center.

Disturbance Classification Scale — *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Disturbance Event — *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Economic (Controllable Demand Response) — Demand-side resource that is dispatched based on an economic decision.

Emergency (Controllable Energy-Voluntary Demand Response) — Demand-side resource curtails during system and/or local capacity constraints.

Energy Conservation — The practice of decreasing the quantity of energy used.

Energy Efficiency — Permanent changes to electricity use through replacement with more efficient end-use devices or more effective operation of existing devices. Generally, it results in reduced consumption across all hours rather than event-driven targeted load reductions.

[141] DCLM is a term defined in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, Updated April 20, 2009 www.nerc.com/files/Glossary_2009April20.pdf

Energy Emergency Alert Levels — The categories for capacity and emergency events based on Reliability Standard EOP—002-0:

- Level 1 — All available resources in use.
    - Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet Firm load, Firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and non-Firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
- Level 2 — Load management procedures in effect.
    - Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
    - Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of Firm load commitments. When time permits, these procedures may include, but are not limited to: Public appeals to reduce demand, Voltage reduction, Interruption of non-Firm end use loads in accordance with applicable contracts, Demand-side management, and Utility load Conservation measures.
- Level 3 — Firm load interruption imminent or in progress.
    - Balancing Authority or Load Serving Entity foresees or has implemented Firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Level (Alert) 2, is only accessible with actions taken to increase transmission transfer capabilities.

Energy Only (Capacity) — energy only resources are generally generating resources that are designated as energy only resources or have elected to be classified as energy only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.

Energy-Price (Controllable Economic Demand Response) — Demand-side resource that reduces energy for incentives.

Energy-Voluntary (Controllable Demand Response) — Demand-side resource curtails voluntarily when offered the opportunity to do so for compensation, but nonperformance is not penalized.

Existing-Certain (Existing Generation Resources) — Existing generation resources available to operate and deliver power within or into the Region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following:

1. Contracted (or Firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment.
2. Where organized markets exist, designated market resource[142] that is eligible to bid into a market or has been designated as a Firm network resource.

[142] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

3. Network Resource[143], as that term is used for FERC *pro forma* or other regulatory approved tariffs.
4. Energy only resources[144] confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[145]
5. Capacity resources that cannot be sold elsewhere.
6. Other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed[146] during the period of analysis in the assessment.

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

Existing-Certain and Net Firm Transactions (%) (Margin Category) — Existing-Certain & Net Firm Transactions minus Net Internal Demand shown as a percent of Net Internal Demand.

Existing Generation Resources — *See **Existing-Certain, Existing-Other, Existing-Inoperable***.

Existing-Inoperable (Existing Generation Resources) — This category contains the 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. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero. This includes all existing generation not included in categories *Existing-Certain* or *Existing-Other*, but is not limited to, the following:

1. Mothballed generation (that cannot be returned to service for the period of the assessment).
2. Other existing but out-of-service generation (that cannot be returned to service for the period of the assessment).
3. This category does not include behind-the-meter generation or non-connected emergency generators that normally do not run.
4. This category does not include partially dismantled units that are not forecasted to return to service.

Existing-Other (Existing Generation Resources) — 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. This category also includes portions of intermittent generation not included in *Existing-Certain*. This category includes, but is not limited to the following:

- A resource with non-Firm or other similar transmission arrangements.

[143] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[144] Energy only resources are generally generating resources that are designated as energy only resources or have elected to be classified as energy only resources and may include generating capacity that can be delivered within the area but may be recallable to another area (Source: 2008 EIA 411 document OMB No. 1905-0129)." Note: Other than wind and solar energy, WECC does not have energy only resources that are counted towards capacity.

[145] Energy only resources with transmission service constraints are to be considered in category Existing-Other.

[146] Energy only resources with transmission service constraints are to be considered in category Existing-Other.

- Energy only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but may be curtailed for any reason.
- Mothballed generation (that may be returned to service for the period of the assessment).
- Portions of variable generation not counted in the Existing-Certain category (*e.g.,* wind, solar, etc. that may not be available or derated during the assessment period).
- Hydro generation not counted as Existing-Certain or derated.
- Generation resources constrained for other reasons.

Expected (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Expected implies that a contract has not been executed, but in negotiation, projected or other. These Purchases or Sales are expected to be Firm.
2. Expected Purchases and Sales should be considered in the reliability assessments.

Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Firm implies a contract has been signed and may be recallable.
2. Firm Purchases and Sales should be reported in the reliability assessments. The purchasing entity should count such capacity in margin calculations. Care should be taken by both entities to appropriate report the generating capacity that is subject to such Firm contract.

Future Generation Resources (*See also **Future-Planned** and **Future-Other***) — This category includes generation resources the reporting entity has a reasonable expectation of coming online during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:

1. Construction has started.
2. Regulatory permits being approved, any one of the following:
    a. Site permit
    b. Construction permit
    c. Environmental permit
3. Regulatory approval has been received to be in the rate base.
4. Approved power purchase agreement.
5. Approved and/or designated as a resource by a market operator.

Future-Other (Future Generation Resources) — This category includes future generating resources that do not qualify in Future-Planned and are not included in the Conceptual category. This category includes, but is not limited to, generation resources during the period of analysis in the assessment that may:

1. Be curtailed or interrupted at any time for any reason.
2. Energy only resources that may not be able to serve load during the period of analysis in the assessment.
3. Variable generation not counted in the Future-Planned category or may not be available or is derated during the assessment period.
4. Hydro generation not counted in category Future-Planned or derated.

5. Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position.

Future-Planned (Future Generation Resources) — Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of analysis in the assessment. This category includes, but is not limited to, the following:

1. Contracted (or Firm) or other similar resource.
2. Where organized markets exist, designated market resource[147] that is eligible to bid into a market or has been designated as a Firm network resource.
3. Network Resource,[148] as that term is used for FERC pro forma or other regulatory approved tariffs.
4. Energy only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[149]
5. Where applicable, included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve.

Load as a Capacity Resource (Controllable Capacity Demand Response) — A resource that commits to pre-specified load reductions when system contingencies arise.[150]

NERC's Bulk Power System Disturbance Classification Scale[151] — The NERC Event Analysis program breaks events into two general classifications: Operating Security Events and Resource Adequacy Events. Each event is categorized during the triage process to help NERC and Regional Event Analysis staff to determine an appropriate level of analysis or review. Similar to scales used to rank large weather systems and storms, NERC's Bulk Power System Event Classification Scale is designed to classify bulk power system disturbances by severity, size, and impact to the general public.

Operating Security Events — Operating reliability events are those that significantly affect the integrity of interconnected system operations. They are divided into 5 categories to take into account different system impacts.

- **Category 1**: An event results in any or combination of the following actions:
    a. The loss of a bulk power transmission component beyond recognized criteria,*i.e.,* single-phase line-to-ground fault with delayed clearing, line tripping due to growing trees, etc.
    b. Frequency below the Low Frequency Trigger Limit (FTL) more than 5 minutes.
    c. Frequency above the High FTL more than 5 minutes.
    d. Partial loss of dc converter station (mono-polar operation).

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[147] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[148] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[149] Energy only resources with transmission service constraints are to be considered in category Future, Other.

[150] These resources are not limited to being dispatched during system contingencies. They may be subject to economic dispatch from wholesale balancing authorities or through a retail tariff and bilateral arrangements with a third-party curtailments service provider. Additionally, this capacity may be used to meet resource adequacy obligations when determining panning Reserve Margins.

[151] http://www.nerc.com/page.php?cid=5%7C252.

e. "Clear-Sky" Inter-area oscillations.
f. Intended and controlled system separation by proper Special Protection Schemes / Remedial Action Schemes (SPS/RAS) action of Alberta from the Western Interconnection, New Brunswick from New England, or Florida from the Eastern Interconnection.
g. Unintended system separation resulting in an island of a combination of load and generation of 20 MW to 300 MW.
h. Proper SPS/RAS actuation resulting in load loss of 100 MW to 500 MW.

- **Category 2**: An event results in any or combination of the following actions:

a. Complete loss of dc converter station.
b. The loss of multiple bulk power transmission components.
c. The loss of an entire switching station (all lines, 100 kV or above).
d. The loss of an entire generation station of 5 or more generators (aggregate stations of 75 MW or higher).
e. Loss of off-site power (LOOP) to a nuclear generating station.
f. The loss of load of 300 MW to 500 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
g. Proper SPS/RAS, UFLS, or UVLS actuation that results in loss of load of 500 MW or greater.
h. The loss of generation (between 1,000 and 2,000 MW in the Eastern Interconnection or Western Interconnection and between 500 MW and 1,000 MW in the Texas or Québec Interconnections).
i. The planned automatic rejection of generation through special protection schemes (SPS) or remedial action schemes (RAS) of less than 3,000 MW in the Western Interconnection, or less than 1,500 MW in the Eastern, Texas, and Québec Interconnections.
j. Unintended system separation resulting in an island of a combination of load and generation of 301 MW to 5,000 MW.
k. SPS/RAS misoperation.

- **Category 3**: An event results in any or combination of the following actions:

a. The loss of load from 500 MW to 1,000 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
b. The unplanned loss of generation (excluding automatic rejection of generation through SPS/RAS) of 2,000 MW or more in the Eastern Interconnection or Western Interconnection, and 1,000 MW or more in the Texas or Québec Interconnections.
c. Unintended system separation resulting in an island of a combination of load and generation of 5,001 MW to 10,000 MW.

- **Category 4**: An event results in any or combination of the following actions:

a. The loss of load from 1,000 MW to 9,999 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
b. Unintended system separation resulting in an island of a combination of load and generation of more than 10,000 MW.

- **Category 5**: An event results in any or combination of the following actions:

a. The loss of load of 10,000 MW or more.
b. The loss of generation of 10,000 MW or more.

Resource Adequacy Events — Adequacy events are divided into three categories based on Standard EOP—002-0 (Capacity and Energy Emergencies).

- **Category A1**: No disturbance events and all available resources in use.
    a. Required Operating Reserves cannot be sustained.
    b. Non-Firm wholesale energy sales have been curtailed.
- **Category A2**: Load management procedures in effect.
    a. Public appeals to reduce demand.
    b. Voltage reduction.
    c. Interruption of non-Firm end per contracts.
    d. Demand-side management.
    e. Utility load Conservation measures.
- **Category A3**: Firm load interruption imminent or in progress.

(NERC) Reference Margin Level (%) — Either the Target Reserve Margin provided by the Region/subregion or NERC assigned 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 Margin Level. If not, NERC assigned 15 percent Reserve Margin for predominately thermal systems and for predominately hydro systems, 10 percent.

Net Internal Demand — Equals the Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

Non-dispatchable (Demand Response) — Demand-side resource curtails according to tariff structure, not instruction from a control center.

Non-Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Non-Firm implies a non-Firm contract has been signed.
2. Non-Firm Purchases and Sales should not be considered in the reliability assessments.

Non-Spin Reserves (Controllable Ancillary Demand Response) — Demand-side resource not connected to the system but capable of serving demand within a specified time.

On-Peak (Capacity) — The amount of capacity that is expected to be available on seasonal peak.

Operating Reliability Events Categories — *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Prospective Capacity Reserve Margin (%) — Prospective Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

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

Provisional (Transaction Category) — A category of Purchases/Imports and Sales/Exports with contracts. Provisional implies that the transactions are under study, but negotiations have not begun. These Purchases and Sales are expected to be provisionally Firm.

Purchases/Imports — *See **Transaction Categories***

Real-Time Pricing (RTP) (Non-dispatchable Time-Sensitive Pricing Demand Response) — Rate and price structure in which the price for electricity typically fluctuates to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.

Reference Margin Level — *See **NERC Reference Margin Level***

Regulation (Controllable Ancillary Demand Response) — Demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.

Renewable Energy — The United States Department of Energy, Energy Efficiency & Renewable Energy glossary defines "Renewable Energy" as "energy derived from resources that are regenerative or for all practical purposes cannot be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource."[152] The government of Canada has a similar definition.[153] Variable generation is a subset of Renewable Energy — See ***Variable Generation***.

Renewables — *See **Renewable Energy***

Reserve Margin (%) — *See **Deliverable Capacity Reserve Margin (%)** and **Prospective Capacity Reserve Margin (%)**.* Roughly, Capacity minus Demand, divided by Demand or (Capacity-Demand)/Demand. Replaced *Capacity Margin(s) (%)* for NERC Assessments in 2009.

Resource Adequacy Events — *See **NERC's Bulk Power System Disturbance Classification Scale***

Sales/Exports Contracts — *See Transaction Categories*

Spinning/Responsive Reserves (Controllable Ancillary Demand Response) — Demand-side resources that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

System Peak Response Transmission Tariff (Non-dispatchable Time-Sensitive Pricing Demand Response) — The rate and/or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges.

Target Reserve Margin (%) — Established target for Reserve Margin by the Region or subregion. Not all Regions report a Target Reserve Margin. The NERC Reference Margin Level is used in those cases where a Target Reserve Margin is not provided.

Total Internal Demand — The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for

[152] http://www1.eere.energy.gov/site_administration/glossary.html#R.
[153] http://www.cleanenergy.gc.ca/index.cfm?action=faq.summary.

station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electric energy use, all non-dispatchable Demand Response programs (such as Time-of-Use, Critical Peak Pricing, Real-time Pricing and System Peak Response Transmission Tariffs) and some dispatchable Demand Response (such as Demand Bidding and Buy-Back). Adjustments for controllable Demand Response should not be incorporated in this value.

Time-of-Use (TOU) (Non-dispatchable Time-Sensitive Pricing Demand Response) — Rate and/or price structures with different unit prices for use during different blocks of time.

Time-Sensitive Pricing (Non-dispatchable Demand Response) — Retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost and/or peak periods.

Transaction Categories (*See also* ***Firm, Expected and Provisional)*** — Contracts for Capacity are defined as an agreement between two or more parties for the Purchase and Sale of generating capacity. Purchase contracts refer to imported capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to exported capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a resource subject to a contract is located in one Region and sold to another Region, the Region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold to the outside Region. The purchasing Region reports such capacity as a purchase, but does not report the capacity of such resource. Transmission must be available for all reported Purchases and Sales.

Transmission-Limited Resources — The amount of transmission-limited generation resources that have known physical deliverability limitations to serve load within the Region. If capacity is limited by both studied transmission limitations and generator derates, the generator derates take precedence. For example, a 100 MW wind farm with a wind capacity variation reduction of 50 MW and a transmission limitation of 60 MW would take the 50 MW wind variation reduction first and list 10 MW in the transmission limitation.

Transmission Loading Relief (TLR) Levels — Various levels of the TLR Procedure from Reliability Standard IRO—006-4 — Reliability Coordination — Transmission Loading Relief:

- TLR Level 1 — Notify Reliability Coordinators of potential SOL or IROL Violations
- TLR Level 2 — Hold transfers at present level to prevent SOL or IROL Violations
- TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service
- TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate a SOL or IROL Violation
- TLR Level 4 — Reconfigure Transmission
- TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service

- TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation
- TLR Level 6 — Emergency Procedures
- TLR Level 0 — TLR concluded

Transmission Status Categories — Transmission additions were categorized using the following criteria:

- Under Construction: Construction of the line has begun
- Planned (any of the following)”
- Permits have been approved to proceed
- Design is complete
- Needed in order to meet a regulatory requirement
- Conceptual (any of the following)
- A line projected in the transmission plan
- A line that is required to meet a NERC TPL Standard or included in a powerflow model and cannot be categorized as “Under Construction” or “Planned”
- Projected transmission lines that are not “Under Construction” or “Planned”

Variable Generation — Variable generation technologies generally refer to generating technologies whose primary energy source varies over time and cannot reasonably be stored to address such variation.[154] Variable generation sources which include wind, solar, ocean and some hydro generation resources are all renewable based. Variable generation in this report refers only to wind and solar resources. There are two major attributes of a variable generator that distinguish it from conventional forms of generation and may impact the bulk power system planning and operations: variability and uncertainty.

Variability — The output of variable generation changes according to the availability of the primary fuel (wind, sunlight and moving water) resulting in fluctuations in the plant output on all time scales.

Uncertainty — The magnitude and timing of variable generation output is less predictable than for conventional generation.

[154] http://www.nerc.com/files/IVGTF_Report_041609.pdf.

Appendix VI: Abbreviations Used in this Report

A/C	Air Conditioning
AEP	American Electric Power
AFC	Available Flowgate Capability
ASM	Ancillary Services Market
ATCLLC	American Transmission Company
ATR	AREA Transmission Review (of NYISO)
AWEA	American Wind Energy Association
BA	Balancing Authorities
BASN	Basin (subregion of WECC)
BCF	Billion cubic feet
BCFD	Billion cubic feet per day
CALN	California-North (subregion of WECC)
CALS	California-South (subregion of WECC)
CANW	WECC-Canada (subregion of WECC)
CFL	Compact Fluorescent Light
CMPA	California-Mexico Power Area
COI	California-Oregon Intertie
COS	Coordinated Outage (transmission) System
CPUC	California Public Utilities Commission
CRO	Contingency Reserve Obligation
CRP	Curtailable Rate Program (Manitoba Hydro)
CRPP	Comprehensive Reliability Planning Process (of NYISO)
DADRP	Day-Ahead Demand Response Program
dc	Direct Current
DCLM	Direct Controlled Load Management
DFW	Dallas/Fort Worth
DLC	Direct Load Control
DOE	U.S. Department of Energy
DSG	Dynamics Study Group
DSI	Direct-served Industry
DSM	Demand-Side Management
DSW	Desert Southwest (subregion of WECC)
DVAR	D-VAR® reactive power compensation system
EDRP	Emergency Demand Response Program
EE	Energy Efficiency
EEA	Energy Emergency Alert
EECP	Emergency Electric Curtailment Plan
EIA	Energy Information Agency (of DOE)
EILS	Emergency Interruptible Load Service (of ERCOT)
EISA	Energy Independence and Security Act of 2007 (USA)
ELCC	Effective Load-carrying Capability
EMTP	Electromagnetic Transient Program
ENS	Energy Not Served

EOP	Emergency Operating Procedure
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FCITC	First Contingency Incremental Transfer Capability
FCM	Forward Capacity Market
FERC	U.S. Federal Energy Regulatory Commission
FP	*Future-Planned*
FO	*Future-Other*
FRCC	Florida Reliability Coordinating Council
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GGGS	Gerald Gentleman Station Stability
GHG	Greenhouse Gas
GRSP	Generation Reserve Sharing Pool (of MAPP)
GTA	Greater Toronto Area
GWh	Gigawatt hours
HDD	Heating Degree Days
HVac	Heating, Ventilating, and Air Conditioning
IA	Interchange Authority
ICAP	Installed Capacity
ICR	Installed Capacity Requirement
IESO	Independent Electric System Operator (in Ontario)
IOU	Investor Owned Utility
IPL/NRI	International Power Line/Northeast Reliability Interconnect Project
IPSI	Integrated Power System Plan
IRM	Installed Reserve Margin
IROL	Interconnection Reliability Operating Limit
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kV	Kilovolts (one thousand volts)
LaaRs	Loads acting as a Resource
LCR	Locational Installed Capacity Requirements
LDC	Load Duration Curve
LFU	Load Forecast Uncertainty
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss Of Load Probability
LOOP	Loss of off-site power
LRP	Long Range Plan
LSE	Load-serving Entities
LTRA	Long-Term Reliability Assessment
LTSG	Long-term Study Group
MAAC	Mid-Atlantic Area Council

Maf	Million acre-feet
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MCRSG	Midwest Contingency Reserve Sharing Group
MEXW	WECC-Mexico (subregion of WECC)
MISO	Midwest Independent Transmission System Operator
MPRP	Maine Power Reliability Program
MRO	Midwest Reliability Organization
MVA	Megavolt amperes
MVAr	Mega-VArs
MW	Megawatts (millions of watts)
MWEX	Minnesota Wisconsin Export
NB	New Brunswick
NBSO	New Brunswick System Operator
NDEX	North Dakota Export Stability Interface
NEEWS	New England East West Solution
NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridor
NOPSG	Northwest Operation and Planning Study Group
NORW	Northwest (subregion of WECC)
NPCC	Northeast Power Coordinating Council
NPDES	National Pollutant Discharge Elimination System
NPPD	Nebraska Public Power District
NSPI	Nova Scotia Power Inc.
NTSG	Near-term Study Group
NWPP	Northwest Power Pool Area (subregion of WECC)
NYISO	New York Independent System Operator
NYPA	New York Planning Authority
NYRSC	New York State Reliability Council, LLC
NYSERDA	New York State Energy and Research Development Agency
OASIS	Open Access Same Time Information Service
OATT	Open Access Transmission Tariff
OP	Operating Procedure
OPA	Ontario Power Authority
OPPD	Omaha Public Power District
ORWG	Operating Reliability Working Group
OTC	Operating Transfer Capability
OVEC	Ohio Valley Electric Corporation
PA	Planning Authority
PACE	PacifiCorp East
PAR	Phase Angle Regulators
PC	NERC Planning Committee
PCAP	Pre-Contingency Action Plans
PCC	Planning Coordination Committee (of WECC)
PJM	PJM Interconnection

PRB	Powder River Basin
PRC	Public Regulation Commission
PRSG	Planned Reserve Sharing Group
PSA	Power Supply Assessment
PUCN	Public Utilities Commission of Nevada
QSE	Qualified Scheduling Entities
RA	Resource Adequacy
RAP	Remedial Action Plan
RAR	Resource Adequacy Requirement
RAS	Reliability Assessment Subcommittee of NERC Planning Committee
RC	Reliability Coordinator
RCC	Reliability Coordinating Committee
RFC	ReliabilityFirst Corporation
RFP	Request For Proposal
RGGI	Regional Greenhouse Gas Initiative
RIS	Resource Issues Subcommittee of NERC Planning Committee
RMR	Reliability Must Run
RMRG	Rocky Mountain Reserve Group
ROCK	Rockies (subregion of WECC)
RP	Reliability Planner
RPM	Reliability Pricing Mode
RRS	Reliability Review Subcommittee
RSG	Reserve Sharing Group
RTEP	Regional Transmission Expansion Plan (for PJM)
RTO	Regional Transmission Organization
RTP	Real-time Pricing
RTWG	Renewable Technologies Working Group
SA	Security Analysis
SasKPower	Saskatchewan Power Corp.
SCADA	Supervisory Control and Data Acquisition
SCC	Seasonal Claimed Capability
SCD	Security Constrained Dispatch
SCDWG	Short Circuit Database Working Group
SCEC	State Capacity Emergency Coordinator (of FRCC)
SCR	Special Case Resources
SEMA	Southeastern Massachusetts
SEPA	State Environmental Protection Administration
SERC	SERC Reliability Corporation
SMUD	Sacramento Municipal Utility District
SOL	System Operating Limits
SPP	Southwest Power Pool
SPS	Special Protection System
SPS/RAS	Special Protection Schemes / Remedial Action Schemes
SRIS	System Reliability Impact Studies
SRWG	System Review Working Group

STATCOM	Static Synchronous Compensator
STEP	SPP Transmission Expansion Plan
SVC	Static VAr Compensation
TCF	Trillion Cubic Feet
TFCP	Task Force on Coordination of Planning
THI	Temperature Humidity Index
TIC	Total Import Capability
TID	Total Internal Demand
TLR	Transmission Loading Relief
TOP	Transmission Operator
TPL	Transmission Planning
TRE	Texas Regional Entity
TRM	Transmission Reliability Margins
TS	Transformer Station
TSP	Transmission Service Provider
TSS	Technical Studies Subcommittee
TVA	Tennessee Valley Authority
USBRLC	United States Bureau of Reclamation Lower Colorado Region
UFLS	Under Frequency Load Shedding Schemes
UVLS	Under Voltage Load-Shedding
VAr	Voltampere reactive
VACAR	Virginia and Carolinas (subregion of SERC)
VSAT	Voltage Stability Assessment Tool
WALC	Western Area Lower Colorado
WECC	Western Electricity Coordinating Council
WTHI	Weighted Temperature-Humidity Index
WUMS	Wisconsin-Upper Michigan Systems

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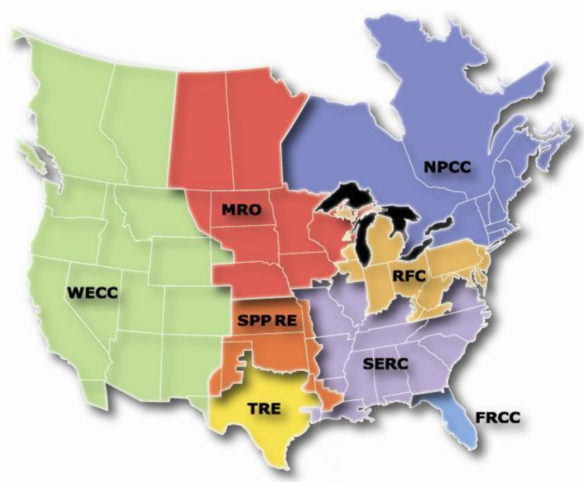

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	ReliabilityFirst Corporation
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

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ERRATA

Version	Date Published	Enhancement(s)
1.0	5/30/2012	Original Release
2.0	6/5/2012	NPCC-Maritimes and NPCC-NYISO table updates; minor formatting corrections.

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