Assessment of Non-Transmission Alternatives to the NEEWS Transmission Projects: Interstate Reliability Project

Redacted Public Version

Prepared for:
Northeast Utilities Service Company and National Grid

Prepared by:
ICF International

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TABLE OF CONTENTS

PAGE

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

LIST OF EXHIBITS

PAGE

List of Exhibits

List of Exhibits

ICF INTERNATIONAL

LIST OF EXHIBITS

LIST OF EXHIBITS

EXECUTIVE SUMMARY

ES.1 Introduction

The Interstate Reliability Project ("Interstate" or "the Project") is a component of the New England East-West Solution (NEEWS). ICF International (ICF) analyzed the potential for Non-Transmission Alternatives (NTA) to defer or displace the Project. ICF found no NTA that would meet the need addressed by the Project, even with aggressive assumptions concerning both installation of available and relevant new power plants in the ISO New England (ISO-NE) Interconnection Queue and implementation of potential demand-side management (DSM) measures.[1] This conclusion is based on the following considerations, which are discussed in more detail in this Executive Summary:

a) Studies show that Interstate solves multiple reliability criteria violations projected within the 10-year planning horizon.[2] The identified violations must be resolved because they are violations of one or more of the reliability standards and criteria of the North American Electric Reliability Corporation (NERC), which the Federal Energy Regulatory Commission (FERC) has established as the U.S. Electric Reliability Organization; the Northeast Planning Coordinating Council, Inc. (NPCC); and ISO-NE. The studies also show that the identified violations occur when the New England transmission grid transfers power across southern New England[3] both from east to west and from west to east, when such transfers are needed most.

b) To function as an alternative for Interstate, an NTA would need to resolve all the violations that Interstate addresses.

c) In the search for an NTA, ICF considered three types of resources: (1) implementation of passive demand resource goals considered by the southern New England states, including aggressive implementation; (2) the addition of generators from the ISO-NE Interconnection Queue; and (3) active demand resources.[4] These resources, alone and in combination, did not produce a feasible NTA solution.

d) Implementation of an NTA solution, were one to be found, would be challenging, compared to implementation of the Interstate Project, because an NTA would involve many parties, locations, and resources.

e) ICF estimated that the cost of hypothetical NTA solutions would be at least 30 times that of Interstate. To develop the hypothetical NTA solution, ICF assumed that unprecedented levels of active demand resources would be available to bridge the gap

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[1] *Power plants were selected from the ISO-NE Interconnection Queue as of April 1st, 2011. Power plants that were irrelevant to solving the identified violations were excluded. Examples are power plants that were very distant from the location of the violations, and plants that did not provide any incremental benefits because the violations within their sub-region had already been resolved (see Chapters 6 and 7).*

[2] *In this study, reliability violations refer to thermal overloads.*

[3] *The study area defined as southern New England includes (but is not limited to) facilities of Northeast Utilities, National Grid USA, and NSTAR in the states of Massachusetts, Rhode Island, and Connecticut.*

[4] *In this study, we refer to demand resources as either passive or active. The sources considered for passive demand resources include energy efficiency and small (distributed) renewable generation. For the latter, state level net metering programs for distributed renewables and programs providing direct funding or subsidies to small renewables were considered. Active demand resources are interruptible load and Real Time Emergency Generator (RTEG).*

between achievable demand and supply resources and the NTA solution. The cost and resources required show that an NTA solution would not be practical and feasible.

f) Recent and on-going changes to the ISO-NE Forward Capacity Market (FCM) rules will make NTAs at the scale required to resolve the regional violations analyzed in this study even less feasible or practical.

ES.2 Interstate Solves Reliability Problems

ES.2.1 ISO-NE Analysis

ISO-NE has concluded that Interstate is needed so that electric customers in southern New England will continue to benefit from uninterrupted electric transmission service even when the electric supply system is under stress from high customer demand, the unavailability of some local generation resources, and unplanned outages of some parts of the system. Federally mandated reliability standards require that transmission systems be planned to be operable under such circumstances. ISO-NE power flow simulations have shown that in 2015, the southern New England transmission system will not meet these standards.

Specifically, ISO-NE identified numerous constraints on the transmission system's capability to transfer power across southern New England both from east to west and from west to east. The Project relieves these constraints by providing a new transmission path connecting Massachusetts, Rhode Island and Connecticut and thus enables the transfer of available power from one part of southern New England to customer load in another location. By better integrating generation and load throughout southern New England, the Project will benefit customers throughout all of New England.

ISO-NE has more than once concluded that Interstate is needed to solve reliability problems in spite of changing system conditions over time.[5] This indicates that in spite of market, programmatic, and other developments in ISO-NE, there is a strong need to solve the identified reliability violations. If market signals are not adequate to meet identified system needs, ISO-NE conducts transmission planning to determine transmission infrastructure that can meet the identified needs.[6]

Potential critical southern New England overloads threaten customer service and grid operations. To continue to operate reliably, the power flowing on each transmission line should remain below the appropriate ratings of the line. When overloads occur, operators may relieve the overload; if the overload persists, protective devices such as circuit breakers may take the overloaded line out of service to prevent system damage. Emergency actions taken by operators or automatic measures to relieve one line's overload could overload other transmission system elements, worsen system conditions, and result in severe power outages or a blackout. It is therefore important to ensure that the system is designed to operate within limits under anticipated emergencies.

Overloads are violations of federally mandated reliability regulations. Each identified potential overload violates one or more of the reliability standards and criteria of NERC, NPCC and ISO-

[5] *The reliability-based transmission needs for southern New England were previously identified in the Southern New England Transmission Reliability (SNETR) Report Needs Analysis dated January 2008. The results of the recent study, reaffirming the need for the Project, are described in the ISO-NE report New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment dated April 2011.*

[6] *ISO New England 2010 Regional System Plan, October 28, 2010, page 14.*

NE. The conclusions of ISO-NE regarding Interstate are based on its requirement to plan and operate the system reliably.

ES.2.2 ICF Analysis

ICF's analysis confirms ISO-NE's finding that Interstate is needed. In an analysis of the operation of the southern New England electric supply system without the Project, ICF identified numerous overloads (that is, violations of equipment thermal limitations) that constrain the transfer of power from east to west and from west to east under contingency conditions. These overloads numbered 206 in 2015 and 6,029 in 2020. The number of system elements experiencing overloads from more than one contingency condition was 20 in 2015 and 53 in 2020.

ICF's analysis also confirms that Interstate eliminates all identified overloads. Specifically, ICF's power-flow analysis confirms that the Interstate Project solves all the 2015 and 2020 thermal violations that constrain the east to west and west to east transfer of power across southern New England, as identified by ISO-NE. This is in spite of the large number of such violations and their wide distribution. Thus, Interstate provides a single integrated solution to numerous transmission system violations under contingency conditions in Massachusetts, Connecticut and Rhode Island.

ES.3 Potentially Available Resources Would Not Produce a Feasible NTA Solution

ES.3.1 NTA Criterion Used

Interstate provides an integrated regional solution for numerous sub-regional transmission issues in southern New England. As a result, a potential NTA to the Project should comprise a set of potentially available non-transmission resources that would resolve all the identified criteria violations in all the sub-regions. This criterion would permit identification of an NTA that did not increase the transmission capacity for east to west and west to east transfers, which is an important attribute of the transmission solution. Thus, ICF's criterion used in its search for an NTA did not require that the NTA provide all of the benefits of the Project.

ES.3.2 Approach

ICF searched for an NTA that would eliminate the thermal violations addressed by Interstate. Had ICF identified such an NTA, it would have gone on to test it for the elimination (or aggravation) of the voltage violations addressed by Interstate. However, the lack of an NTA that would solve the thermal violations made an evaluation of the voltage issues pointless. The search for an NTA that would eliminate the thermal violations involved a three step process.

a) First, ICF identified the extent to which demand would have to be decreased in southern New England in order to eliminate the violations without the addition of new transmission or generation resources (Chapter 4).

b) Second, ICF created potential NTA candidates and tested whether they eliminated the violations. The three NTA candidates tested were: (1) an NTA based on passive demand side programs, including a reference and an aggressive set of passive demand side programs (Chapter 5); (2) an NTA based only on potentially available supply side resources from the ISO-NE Interconnection Queue (Chapter 6); and (3) an NTA based on a combination of passive demand and supply resources (Chapter 7).

c) Third, for the demand only NTA and the combination NTA, ICF estimated the amount of active demand side resources required to bridge the gap between resources and demand to produce an NTA solution that would resolve all the identified violations. ICF then assessed the reasonableness of achieving the required amount of active demand resources. ICF used this approach because the amount of potentially available active demand resources is more difficult to estimate than that of passive demand resources, or supply side resources.

ES.3.3 Demand Reductions Required for an NTA Solution

The first step in ICF's search for an NTA involved an analysis to determine the level of load reduction required to solve the identified thermal violations without the addition of new transmission or generation resources. This is referred to as a Critical Load Level (CLL) analysis (see discussion in Chapter 4). The CLL analysis involves identifying a load reduction that just solves the thermal violations, and thus the load level at which the identified thermal violations begin to occur. To derive the CLL, the predicted peak load in each sub-region was reduced incrementally until thermal violations in that sub-area were eliminated. Using this technique, ICF determined that in 2015, load in southern New England would have to be reduced by 3,400 MW, or 15 percent of the load in that year, to solve the identified thermal violations under N-1-1 contingency conditions. In 2020, the required load reduction was 5,300 MW, or 20 percent of the predicted peak load for that year.

ES.3.4 Passive Demand Side Resource NTA

The second step in ICF's search for an NTA involved estimating potentially available resources, including passive demand resources, active demand resources, and new generation. ICF reviewed potentially available passive demand resources under two sub-cases, the reference and aggressive policy cases (see discussion in Chapter 5). The sources considered for passive demand resources include energy efficiency and small (distributed) generation. For the latter, state level net metering programs for distributed renewables were considered as were programs providing direct funding or subsidies to small renewables. Within New England, the utility-sponsored programs reflect the majority of passive resources which are not already included in the baseline load forecasts. These programs are subject to regulatory approvals at the state level, and are also frequently backed with state level funding to support utility implementation of programs for consumers. These programs are not considered responsive to real-time market conditions, but are rather influenced by total costs and benefits over the program life. Exhibit ES-1 shows the passive demand resource potential estimated for each state under the reference and aggressive demand resource cases. These amounts are incremental to the approximately 1,100 MW of passive demand resources in southern New England in the base case.

Exhibit ES-1
Incremental Potential Passive Demand Resource by Sub-Region – 2015 and 2020

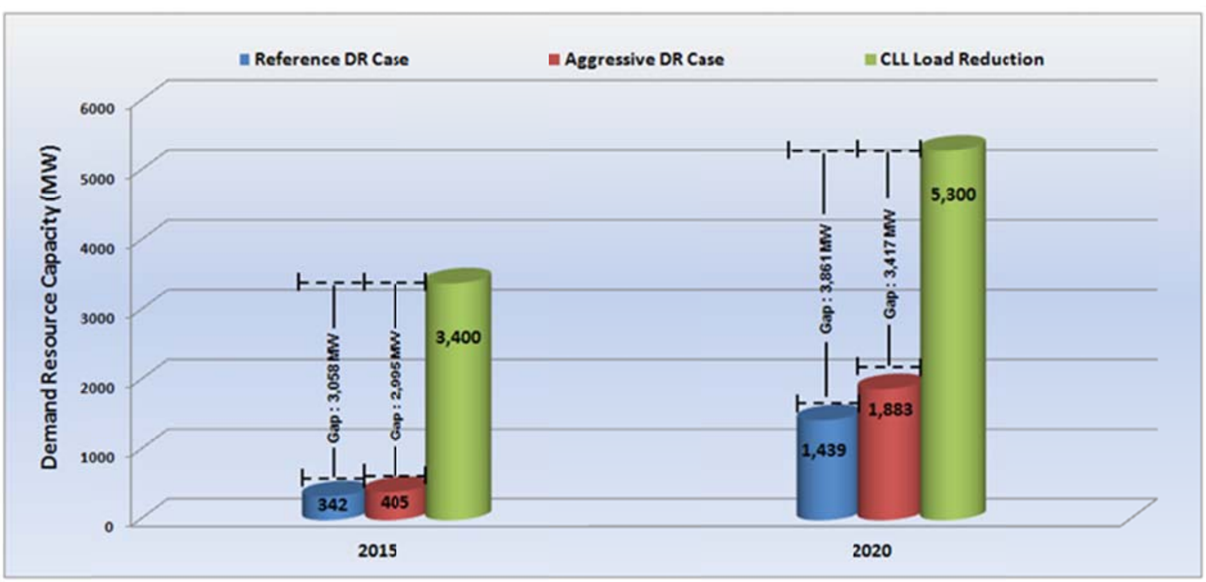
Area of Concern	Year	Incremental Passive DR Applied (MW)	
		Reference Case	Aggressive Case
Rhode Island	2015	47	61
	2020	161	235
Western NE [1]	2015	86	113
	2020	380	538
Eastern NE	2015	208	231
	2020	897	1,110
Total	2015	342	405
	2020	1,439	1,883

NOTE: Values are shown at the load bus level and include 5.5 percent distribution losses from end use level.

[1] Massachusetts is split between Western NE and Eastern NE. Roughly 12 percent of Massachusetts falls in Western NE while the remaining falls into Eastern NE.

ICF determined that, standing alone, the passive demand resources are insufficient to resolve the identified violations and thus to provide an NTA solution (Chapter 5). As shown in Exhibit ES-2, the amount of load reduction required to address the identified violations exceeded the estimated maximum available incremental passive demand side resources by 2,995 MW in 2015 (3,400 MW - 405 MW = 2,995 MW). The gap was nearly 90 percent of the required load reduction under the CLL analysis in 2015; and that very large gap would need to be filled in a short time.

Exhibit ES-2
Available and Required Demand Resources to Resolve All Violations in Demand NTA



In 2020, more incremental passive demand resources are available at 1,439 MW to 1,883 MW, but the gap is still large at 64 percent to 73 percent of the required amount (see Exhibit ES-2). This gap occurs even though ICF examined aggressive estimates of available passive demand side resources.

Since the analyses presented here-in were completed, ISO-NE has presented initial results of their effort to include projections of energy efficiency in forward analyses for periods beyond the current FCM horizon. The results were presented at the PAC meeting held on November 16, 2011 (see "ISO-NE Proof of Concept Forecast of New State-Sponsored Energy Efficiency"). The draft results presented by ISO span the calendar years 2014 to 2020. Just before finalizing this report, ICF had the opportunity to conduct a preliminary review of the ISO-NE presentation and to compare their draft results of that analysis to those used by ICF. ICF found that the quantities presented by ISO-NE were generally consistent with the assumed passive Demand Resources in the ICF Reference Case analyses for the southern New England load zones through 2020. Please note that ICF additionally modeled an Aggressive Case which included even greater quantities of passive Demand Resources in southern New England.

ES.3.5 Active Demand Resources Required for a Demand-Only NTA Solution

In light of the substantial difference between potentially achievable passive demand resources and the load reductions required to reach the CLL (up to 3,058 MW of load reduction in 2015 and 3,861 MW of load reduction in 2020 in the reference demand resource case), ICF considered the reasonableness of closing this gap solely through the procurement of active demand side resources, specifically, through incentivizing customers to agree to enforceable interruption of service as needed to reduce load.

ICF did not develop a specific forecast of available active demand resources as part of this study. Rather, ICF calculated the additional amount of active demand resources that would be required to close the identified gap and compared this to the amount expected in the market by 2015 based on the levels available in the FCM. Based on this information, ICF assessed the potential that sufficient active demand resources will be available to meet the required levels by 2015 and 2020.

ES.3.5.1 Active Demand Resource Performance

Active demand resources do not necessarily provide a one MW load reduction for every one MW cleared. To estimate the additional quantity of active demand resources that would be required to provide load reductions of 3,058 MW to 3,861 MW, ICF used the historical performance of active resources to determine an assumed performance rate for such resources. ISO-NE has recently proposed updating the metric used to determine the performance rate for regional demand response resources for FCA #6. Through FCA #5, ISO used the historical performance rating of the demand response available during the FCM transition period which reflected an average of several past years of OP4 events and audits to calculate performance rates. The transition period resources do not reflect the resources cleared in the FCM auctions. For FCA #6, ISO-NE is proposing to adopt performance rates based on the performance results for actual cleared resources for the first year of the FCM (summer 2010). The proposed performance rates reflect the single year of performance for actual FCM demand resources. As such, the proposed rates are more reflective of resources participating in the market, but lack the potential for variability in performance over time as the measurement is currently available for only one year.

ICF used each of these methods to calculate the performance rate and the required amount of active demand resources in each sub-region. ICF then aggregated the resources required in each sub-region to determine the total active demand resources required in southern New England. The results are shown in Exhibit ES-3. For example, using the FCA #6 zonal performance rates, 4,157 MW of active demand resource capacity is required to provide the equivalent of a 3,058 load reduction in 2015 in the reference demand resource case, resulting in an average performance rate of 74 percent for southern New England (i.e., 3,058/4,157 = 0.74).

Exhibit ES-3
Estimated Active Demand Resources Required for Demand NTA

Scenario	Year	Total Gap	Required Resources Based on FCA #5 Performance Factors		Required Resources Based on FCA #6 Performance Factors	
			Average Performance Rate	Resources Required to Fill Gap	Average Performance Rate	Resources Required to Fill Gap
		MW	%	MW	MW	MW
Reference DR Case	2015	3,058	67%	5,070	74%	4,157
	2020	3,861	67%	6,287	76%	5,058
Aggressive DR Case	2015	2,995	60%	4,979	73%	4,099
	2020	3,417	61%	5,603	76%	4,495

The average performance rate for southern New England varies by year and by case because it depends on both the zonal performance rate and the amount of demand resources required in each sub-region. See Section I of Appendix C for additional detail on the calculation of performance rates and required active demand resources.

This approach provides a conservatively low estimate of the active demand resources required to fill the gap, given that it does not consider the increased frequency at which the active demand resources would be called on to perform as the reliance on these resources increases.

This increase in frequency could lead to even lower performance, a problem referred to as "fatigue".

ES.3.5.2 Comparison with Existing Active Demand Resources

To provide perspective on the reasonableness of achieving between 4,000 MW and 6,000 MW of active demand resources to fill the gap, ICF compared these levels with the FCA #5 results for active demand resources available for use in summer 2014, which are presented in Exhibit ES-4.

The total amount of Real Time Demand Response capacity in ISO-NE that qualified in FCA #5 was 1,667 MW. Of this amount, 1,382 MW cleared in the FCA.[7] Only approximately 70 percent, or 971 MW of this cleared active demand resources exists for use in southern New England; the rest is located outside southern New England.

[7] The only active demand side resource available is interruptible load, generally referred to as Real Time Demand Response. This is because the other active demand resource, Real Time Emergency Generation, is not included in ISO-NE planning. (Source: New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment, April 2011, Southern New England Regional Working Group, ISO New England, pages 19 and 27.)

Exhibit ES-4
Demand Resources in FCA #5 – ISO-NE

FCA 5 Demand Resources	Cleared	Qualified	Cleared	Qualified
	MW	MW	% of total	% of total
On Peak – Passive	1,134	1,203	32.7%	31.4%
Seasonal Peak – Passive	352	360	10.1%	9.4%
Real Time Demand Response – Active	1,382	1,667	39.9%	43.5%
Real-Time Emergency Generation – Active But Not Included in Planning	722	915	17.3%	15.7%
Total	3,590	4,145		
Total with 600 MW Real-Time Emergency Generation Limit	3,468	3,830	100.0%	100.0%

Note: Qualified southern New England real-time demand response was 1,207 MW before de-list bids or 1,102 MW after de-list bids. Cleared real-time demand response in southern New England was 971 MW or 70 percent of 1,382 MW.Source: ISO-NE.

In contrast, in 2015, between 4,099 MW and 4,157 MW of incremental active demand resources are required in southern New England to bridge the gap between potentially achievable passive demand resources and the CLL, implying that in a single year the total available active demand resources would need to grow by roughly 372 percent to 377 percent (see Exhibit ES-5). Through 2020, the implied growth rate would need to be 31 percent to 33 percent per year to achieve the required incremental 4,495 MW to 5,058 MW needed above FCA #5 levels.

Exhibit ES-5
Growth in Active Demand Resources Required for a Demand-Side Only NTA

Parameter	2015	2020
FCA #5 (2014/15) Qualified Active Demand Response Resources (MW)[1]	1,102	1,102
Incremental Active Demand Resources Required to Satisfy the CLL Gap (MW)[2]	4,099 – 4,157	4,495 – 5,058
Total Active Demand Response	5,201 – 5,259	5,597 – 6160
Annual Percentage Growth (%)	372-377%	31-33%

[1] The qualified resources from FCA #5 are used as a proxy for the total available demand response resources available for the summer of 2014 as of today. Total is shown for the RI, CT, and MA load zones only as the area of concern. The total qualified Real Time Demand Response Resource for all of New England is 1,667 MW. Within RI, CT and MA load zones, the qualified resources, 1,207 MW of capacity qualified, of this total, 105 MW were accepted for delist, resulting in qualified Real Time Demand Response Resources of 1,102 MW in Southern New England.

[2] Based on performance levels assumed in FCA #6. Estimates will be higher if performance levels assumed in FCA #5 are used.

As shown in Exhibit ES-6, the availability of active real time demand response in ISO-NE increased from 864 MW to 1,382 MW, an average of 12 percent per auction, between FCA #1 and FCA #5. Growth in total active resources, excluding Real-Time Emergency Generation was less, at only 9 percent. The increase in active real time demand response in southern New England was roughly 350 MW to 400 MW over this same time period. This is well below the rate of growth required to implement a demand-side-only NTA.

Exhibit ES-6
Demand Resource by Category Starting in June 2010 – ISO-NE

Resource Type	DR Category	Capacity (MW)				
		FCA #1	FCA #2	FCA #3	FCA #4	FCA #5
On-Peak Demand Resource	Passive	554	709	799	970	1,134
Real-Time Demand Response Resource	Active	864	915	1,194	1,363	1,382
Critical Peak Demand Resource	Active	106	285	--	--	--
Real-Time Emergency Generation Resource[1]	Active	875	759	630	688	722
Seasonal Peak Demand Resource	Passive	146	269	273	328	352
Total		**2,544**	**2,937**	**2,898**	**3,349**	**3,590**

Notes: Demand resources in southern New England are less than shown. FCA #1 represents the summer of 2010 while FCA #5 is reflective of the summer 2014.

[1] Real-Time Emergency Generation is capped at a contribution level of 600 MW, although additional resources may clear and receive a prorate price, the installed capacity contribution is limited to 600 MW. Values shown reflect the uncapped levels.

In light of the massive and rapid increase in active demand response resources that would be required, ICF concluded that a demand resource-only NTA solution to the identified thermal overloads would not be practical. Even if it were feasible, it would be very expensive. An approximate estimated average cost of incremental demand resource would be roughly 25 times the cost of the Project on a capitalized basis. The cost calculations are provided in Appendix E.

ES.3.6 Generation NTA

ICF also developed a generation-only NTA based on the potential generators listed in the ISO-NE interconnection queue. The generation-only NTA assumed that 1,302 MW of new generation would be added within southern New England by 2015, and that all generation currently proposed in southern New England in the ISO-NE queue (a total of 2,850 MW) would be added by 2020. The generation-only NTA decreased thermal violations by 56 percent and 53 percent in 2015 and 2020, respectively. It also decreased the number of elements overloaded by 15 percent and 42 percent in 2015 and 2020, respectively (see Exhibit ES-7). In light of the significant number of remaining thermal violations (2,817 in 2020) and overloaded elements (31 in 2020), ICF concluded that there is no feasible generation-only NTA that would resolve the identified violations. ICF therefore proceeded to evaluate an NTA that combines generation and demand-side resources. The analysis of the generation NTA is discussed in Chapter 6.

Exhibit ES-7
Summary of Reliability Criteria Violations for Generation NTA

Year	Number of Thermal Violations			Number of Elements Overloaded		
	Needs Assessment	Generation NTA	% Reduction	Needs Assessment	Generation NTA	% Reduction
2015	206	90	56%	20	17	15%
2020	6,029	2,817	53%	53	31	42%

ES.3.7 Combination of Generation and Passive Demand Resources

ICF developed "Combination NTAs" by combining southern New England generation resources selected from the ISO-NE Interconnection Queue with both reference and aggressive levels of passive demand side resources (see discussion in Chapter 7). Under the Combination NTA using reference levels of passive demand resources, the number of thermal violations fell 63 percent in 2015 and 98 percent in 2020, while the number of elements overloaded fell 20 percent in 2015 and 64 percent in 2020. Under the Combination NTA using aggressive levels of passive demand resources, the reductions were only modestly higher. The results are shown in Exhibit ES-8.

Exhibit ES-8
Summary of Reliability Criteria Violations for Reference DR Combination NTA

Case	Year	Number of Thermal Violations			Number of Elements Overloaded		
		Needs Assessment	Combination NTA	Percent Reduction	Needs Assessment	Combination NTA	Percent Reduction
NTA With Reference Level Demand Resource	2015	206	77	63%	20	16	20%
	2020	6,029	124	98%	53	19	64%
NTA With Aggressive Level Demand Resource	2015	206	72	65%	20	15	25%
	2020	6,029	84	99%	53	17	68%

In the Combination NTAs available passive demand resources were added first. Generation resources available in the Interconnection Queue were then added in an attempt to resolve the remaining violations. Exhibit ES-9 shows the supply and demand resource capacity added to the Combination NTAs. In both Rhode Island and Eastern NE violations remained even after all available supply and demand side resources had been added. However, the availability of passive demand resources in the Combination NTAs reduced the amount of incremental generation required to resolve violations in Western NE, relative to the generation NTA.

ES.3.7.1 CLL Analysis with New Generation in Place

To provide a clearer picture of the impact of potential generation additions on the effectiveness of the NTA, ICF recalculated the CLL with the new generation capacity shown in Exhibit ES-9 in place. This new analysis demonstrates that in 2015, with new generation in, an incremental

2,416 MW of load reduction would be needed to resolve all the violations addressed by the Interstate Project (see Exhibit ES-10). Of this, 405 MW could be provided by the passive demand resources using the aggressive level assumptions; this leaves at least 2,011 MW to be provided through active demand response. In 2020, the required demand reduction would be at least 4,820 MW, of which up to 1,883 MW could be provided by passive demand resources. This leaves 2,937 MW to be provided through active demand response. Thus, even with aggressive assumptions on passive demand resources and generation additions from the ISO-NE Interconnection Queue, a large amount of incremental demand reduction was still required.

Exhibit ES-9
Incremental Supply and Demand Resource Capacity in Combination NTA Cases

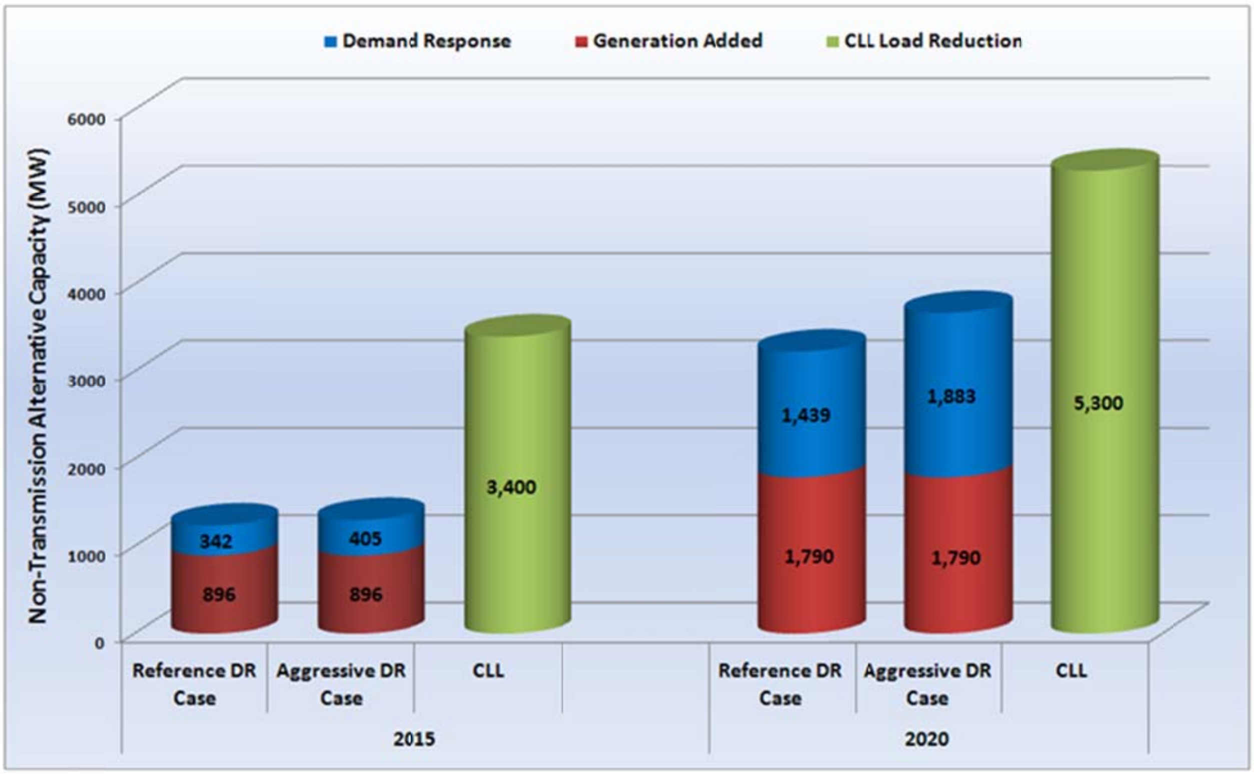


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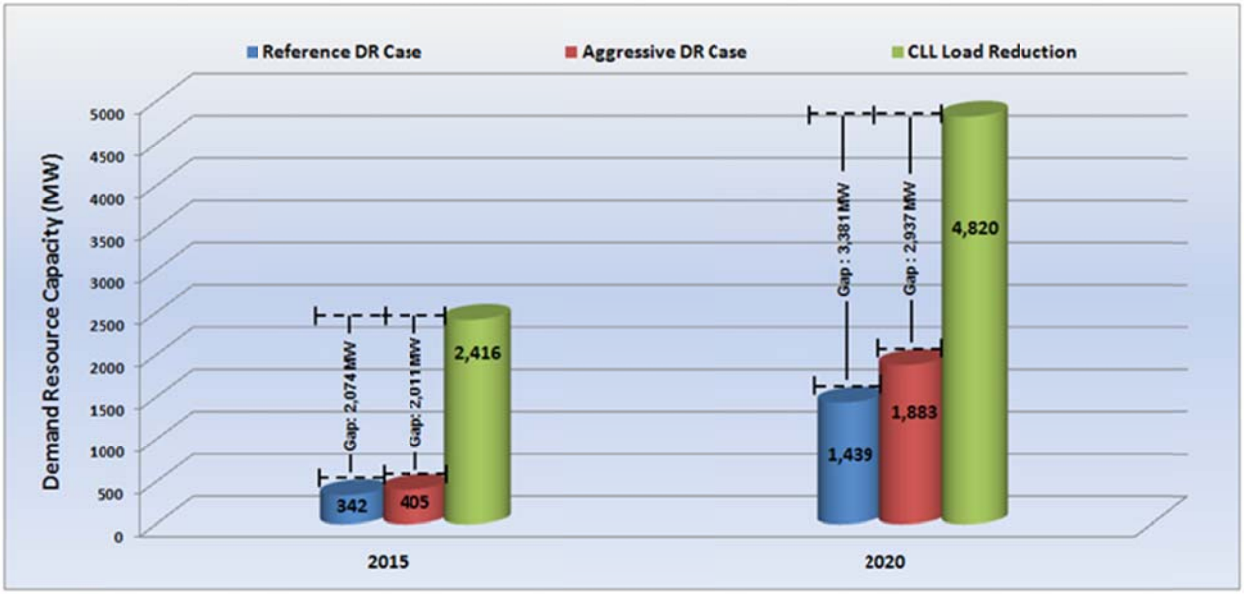
Exhibit ES-10
Available and Required Demand Resources to Resolve All Violations in Combination NTA



ES.3.7.2 Active Demand Resources Required for a Combination NTA Solution

For each sub-region, ICF calculated the performance rate of active demand resources and the level of such resources required to fill the gap between passive demand resources and the CLL. ICF then aggregated the sub-regional values to determine the values for southern New England. ICF used performance rates based on the performance level assumptions in both FCA #5 and FCA #6. The results are shown in Exhibit ES-11. For example, using the FCA #6 zonal performance rates, the total required incremental active demand resources are a minimum of 2,754 MW to 2,835 MW in 2015 and 4,083 MW to 4,667 MW in 2020. The required amounts will be higher if FCA #5 performance rates are assumed.

Exhibit ES-11
Estimated Active Demand Resources Required for Combination NTA Solution

Scenario	Year	Total Gap	Required Resources Based on FCA #5 Performance Factors		Required Resources Based on FCA #6 Performance Factors	
			Average Performance Rate	Resources Required to Fill Gap	Average Performance Rate	Resources Required to Fill Gap
		MW	%	MW	MW	MW
Reference DR Case	2015	2,075	60%	3,482	73%	2,835
	2020	3,382	60%	5,568	72%	4,667
Aggressive DR Case	2015	2,011	59%	3,381	73%	2,754
	2020	2,937	59%	4,871	73%	4,083

The average performance rate for southern New England varies by year and by case because it depends on both the sub-regional performance rate and the amount required in each sub-region. See Section II of Appendix C for additional detail on the calculation of performance rates and required active demand resources.

ES.3.7.3 Comparison with Existing Active Demand Resources

Exhibit ES-12 shows the active demand resources in southern New England that qualified in FCA #5. It also shows the level of active demand resources required to produce a Combination NTA solution, assuming FCA #6 performance rates. In order to meet reliability criteria in 2015 using potential new generation, passive demand resources, and active demand resources (but no transmission), the amount of active demand resources would need to increase by 3.5 times between 2014 and 2015. In order to satisfy reliability criteria by 2020, an average annual growth rate of approximately 29 percent to 32 percent in active demand resource would be required between 2014 and 2020. As described in Exhibit ES-6, the availability of active real-time demand response in ISO-NE increased by an average of 12 percent between FCA #1 and FCA #5. In southern New England the increase was approximately 350 MW to 400 MW. This is well below the level required to implement a Combination NTA solution. Therefore, this option was not considered feasible. If FCA #5 performance rates are assumed, the required amounts would be higher.

Exhibit ES-12
Unprecedented Growth in Active Demand Resources Required for Combination NTA Solution

Parameter	Reference DR Case		Aggressive DR Case	
	2015	2020	2015	2020
FCA #5 (2014/15) Qualified Active Demand Resources (MW)[1]	1,102	1,102	1,102	1,102
Incremental Active Demand Resource Required to Eliminate Thermal Violations in the Combination Case (MW)	2,835	4,667	2,754	4,083
Total Active Demand Resources Required to Eliminate Thermal Violations in the Combination NTA (MW)	3,937	5,769	3,856	5,185
Annual Percentage Growth (%)[2]	257%	32%	250%	29%

[1] Total is shown for the RI, CT, and MA load zones only as the area of concern. Active real time demand response only.

[2] Reference DR Case growth rate is 257% (= 3,937 MW / 1,102 MW – 1) in 2015 and 32% (= (5,769 MW / 1102 MW)^(1/6) – 1). The growth rates for the Aggressive DR Case can be calculated in a similar manner.

ES.3.8 Salem Harbor Power Plant

All of the analyses described above were conducted using the Base Case load flows from ISO-NE's analysis of the NEEWS project. These load flows assume that the Salem Harbor generators are in service throughout the planning period. Recently, the owner of the Salem Harbor generators has indicated its intention to retire the Salem Harbor units by summer, 2014 and ISO-NE has directed Transmission Owners to assume that Salem Harbor is out of service in all needs analyses of the system from 2014 forward. Therefore, ICF analyzed a sensitivity scenario in which the Salem Harbor power plant was retired. Under this scenario, the number of relevant violations in the Combo Case increased, increasing the amount of resources required for an NTA. The Salem Harbor sensitivity is discussed in Section 7.3. In contrast, Interstate solved these additional violations.

This retirement may be a harbinger of additional power plant retirements for the following reasons. First, there are many old plants in ISO-NE. Specifically, as described in Appendix F, as of 2010, 20 percent of ISO-NE generating capacity is greater than 40 years old, hence, older than the typical original book lifetimes, and 3 percent is greater than 50 years old. By 2020, the amount greater than 50 years old will be 20 percent assuming no changes to the fleet from 2010. Second, environmental regulations are tightening, including Hazardous Air Pollutant (HAPs), National Ambient Air Quality (NAAQS), Greenhouse Gas controls such as RGGI, new coal combustion residue and cooling water regulations. The owners of these plants may not find it economic to invest in new air pollution control equipment, and instead, may choose to retire the units. Third, forthcoming changes in the FCM facilitate power plant retirement compared to previous FCM rules as discussed below.

ES.3.9 Conclusion – Feasible NTA Solution Not Found

ICF did not find an NTA that solved all the identified violations in southern New England using potentially available resources. This is in spite of ICF's search for a passive demand-only NTA, a supply side NTA, and a combination case NTA involving both passive demand and supply side resources. While it is difficult to develop a precise estimate of the amount of active demand resources that will be available, ICF found that in all cases, the incremental amount of active demand resources required to produce an NTA solution was so large that it was impractical to achieve through the implementation of active demand resource programs.

ES.4 NTAs Face Significant Implementation Challenges

Given unlimited resources and the necessary time to develop new generation, it might be possible to design a hypothetical NTA for the Interstate project. However, such an NTA would be challenging to implement compared to the Project. This section discusses five NTA implementation challenges.

ES.4.1 NTA Implementation Scope

Interstate is a single integrated solution to multiple violations that occur over a broad area of the southern New England electric system. It would employ proven technology and would be administered by ISO-NE, a centralized expert authority. Also, the Project would be constructed by experienced transmission owners. In contrast, the hypothetical NTA likely would involve numerous power plants and demand resources at multiple locations. As the number of sub-projects multiply, the potential for unexpected problems in terms of permitting, financing, construction, testing, and operation increases. Approximately 75 percent of the projects in the Interconnection Queue fail to be commercialized. Also, demand-only or combination NTA would require the co-ordination of many entities, most responding to financial incentives, without experience in or commitment to solving transmission security problems. As the scope of the NTA solution increases and the economic benefit of NTAs decreases, e.g., decreases in the electrical energy prices per MW added, the ability to implement a multi-state NTA decreases.

ES.4.2 Multi-State Implementation

NTA implementation of the scope required is an especially difficult problem because it involves three states. There are no clearly established and centralized multi-state procedures for NTA implementation. Each state must have the procedures and structures in place to implement the NTA – e.g., contracting, permitting, etc. Also, the states must be able to effectuate long-term contracts with NTA providers, especially providers of supply based NTAs.[8] This is because NTAs will most likely require contracts and programmatic support. Even if an NTA could be found, it would be a challenge for a state to pursue a contract in the absence of the appropriate procedures and structures, even if the state was interested.

ES.4.3 Risk of Over-Reliance on Demand Resources

ISO-NE already relies heavily on demand resources. Further reliance on demand resources via a demand-only or combination NTA increases the concerns related to the risks of this reliance:

- In its FCA #5, ISO-NE procured 11 percent of its resource requirements via demand resources. New market rules such as the elimination of the FCM price floor (scheduled for FCA #8 in 2013) and the potential retirement of power plants due to age and/or new environmental restrictions will tend to eliminate supply resources. In a scenario in which excess supply resources were to leave the market (i.e., about 3,700 MW or about 2,400 MW with the potential loss of Vermont Yankee and the loss of Salem Harbor), demand resources would contribute fully 80 percent of ISO-NE local reserves. At present, only 60 percent of the demand resources are active.[9]

- Reliance on demand resources in such a scenario would become more frequent.[10] There may be a risk that the New England region could be exposed to significant attrition of active demand resources by the "fatigue" of being called on extensively and repeatedly in hot weather to decrease load. Under the FCM, interruptible load contracting is for a single year, so that a party who agrees to service interruptions can leave the DSM program on short notice and with little or no financial penalty relative to never having participated. Although there is as yet no body of ISO-NE data by which the effect of this fatigue factor can be documented and measured, it is a serious concern.

- In order to make agreements to accept interrupted service reliable enough for large scale use in an NTA, new program features would most likely be required. These could include longer contract periods with longer notice periods required for withdrawal to accommodate the longer lead time for transmission relative to generation; greater penalties for non-performance; technology to allow system operators to interrupt service to a participant without relying on the participant's voluntary compliance; and greater evergreen provisions (e.g., legal provisions to obligate the new owner of a contracted house or business to honor the contract).

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[8] *The 2010 RSP states that ISO-NE does not have the authority to build needed resources or transmission. Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 14.*

[9] Historically, reserve capacity has been controlled by system operators. Hence, systems are in place for determining the operational status and performance of the plants. In contrast, passive demand resources are not controlled by operators and not subject to the same tracking systems. Hence, the operators might not be aware that there are limitations on the use of these resources during periods when reserves are required to maintain service, and, hence, there are less reserves available. For example, distributed generation included as a passive demand resource is not under operator control and might fail to operate. Also, the estimates of the amount of energy efficiency achieved might be in error, and operators may not have sufficiently accurate information that this type of reserve is not available.

[10] In the event of a contingency additional resources are required. To the extent that NTA resources are supply, then the region is less reliant on demand resources – e.g., active DR is not used. Conversely, if NTA resources are all demand resources, then the demand resource usage will be added to the amount and frequency of demand resources called upon separate from the existence of a contingency.

ES.4.4 Supply NTA Risks

Supply NTAs (new generation) would likely involve Contracts For Differences under which the ratepayers undertake to make up the shortfall that may occur if a new plant's revenue requirements exceed its market-based earnings in the ISO-NE markets. ICF estimated that the capital costs for the supply NTAs could be up to approximately 2.4 billion dollars for one of the combination generation and demand resource scenarios analyzed (see Appendix E). ISO-NE markets can have volatile prices. This creates large risks for ratepayers that the Contracts For Differences payment to the power plant will have to be large.

ES.4.5 Capital Costs

Even though no feasible NTA was found, the hypothetical demand and supply NTAs examined had capital costs of at least 15 billion or roughly 30 times the cost of the Interstate Project. The supply costs were based on the capital costs of new gas-fired combined cycles, the most common new power plant type in ISO-NE. The passive demand resource cost estimate is based on program cost estimates from the states. Active demand resource costs were based on the annual payment required to obtain voluntary consent to interruption. This annual cost was based on estimates of the costs to consumers of interruption of service referred to as the Value of Lost Load (VoLL) and estimated frequency of interruption. Annual estimated VoLL costs were capitalized at a utility cost of capital.

ICF did not examine the potential economic benefits of NTAs because these high costs decreased the likelihood that benefits would exceed costs. Also, and more importantly, the analysis was not needed due to the failure of the NTAs to meet the identified need by resolving the thermal violations in southern New England solved by the Project.

ES.5 New ISO-NE Rules Make NTAs Even Less Practical

Between February 2010 and April 2011, ISO-NE, FERC, NEPOOL and others were involved in a process that changed the FCM rules.[11] The process was focused on improving price signals in ISO-NE. One effect of the changes to the rules is that NTAs became less economically attractive to regulators and consumers because the new rules eliminate or greatly decrease the potential for out-of-market NTAs to depress the FCM price. A second effect is to create greater emphasis on the ability to transmit power across zones in ISO-NE in order to maintain reliability and to moderate FCM price changes. This effect is due to the following changes:

- Delists or retirements became more likely due to the forthcoming elimination of the FCM price floor which maintained excess capacity in ISO-NE in previous FCAs.
- Delists or retirements also became more likely due to the forthcoming implementation of a "model all zones all the time" policy. Previously, only import and export constrained zones were separately modeled apart from the region as a whole, and generation owners could not respond to lower prices and decide to retire or delist during the forward capacity auction.

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[11] *The rules and their changes are discussed further in Appendix F. Implementation is scheduled to begin for FCA #7 and the price floor will be embedded in FCA #8.*

- Local zonal capacity requirements are being increased via a new approach to setting local supply sourcing minimums.

ES.6 Transmission Offers a Flexible Solution to Reliability Problems and Increasing Deliverability

Interstate solves reliability problems bi-directionally. In contrast, NTAs that solve reliability problems associated with power flows in one direction only will not necessarily respond to other reliability needs served by the Interstate Project.

Interstate also increases the transfer capability across two of the most significant southern New England transmission interfaces – e.g., the New England East-West and Connecticut Import Interfaces. Transmission additions like Interstate increase deliverability in both directions. Thus, if an insufficiency of resources occurs on either the western or eastern portion of southern New England, transmission helps solve the problem. For example, Interstate increases both Connecticut import capability and Connecticut export capability. Since future resource trends are uncertain, this flexibility is valuable to consumers who otherwise face risks of being in a resource deficient sub-zone. Future resource trends are uncertain because of uncertainties in load growth, power plant retirements, environmental regulations, demand resource policy and availability, FCM policy, and other factors.

ES.7 Conclusion

The Interstate Reliability Project is needed to eliminate constraints on the transfer of power across southern New England, from west to east and from east to west when the system is under stress, and thus, to maintain customer service and comply with applicable reliability standards and criteria. No feasible and practical NTA that would meet these needs was found in an intense and wide-ranging search.

CHAPTER 1
The Interstate Reliability Project

1.1 Introduction

The Interstate Reliability Project ("Interstate" or the "Project") is a transmission upgrade project proposed by National Grid and Northeast Utilities Service Company ("NUSCO") to alleviate transmission constraints in Connecticut, Rhode Island, and Massachusetts, the three states in southern New England. The Project consists of a set of transmission upgrades that are designed to reinforce segments of the New England transmission system that are major constraints or limiting elements in southern New England. The Project is part of the larger New England East-West Solution (NEEWS) which, in addition to the Interstate Reliability Project, includes three other major transmission projects:

- Rhode Island Reliability Project
- Greater Springfield Reliability Project
- Central Connecticut Reliability Project

These four components of the NEEWS project in combination were selected as the most effective approach to address major reliability concerns identified by ISO New England (ISO-NE) in southern New England.[12] The four components address the need for additional 345/115 kV transformation and contingency coverage in the Rhode Island area, the need for reinforcements in the Springfield, Massachusetts area, and the need for increased transfer capability into and through Connecticut.[13] The reliability-based transmission needs for southern New England were previously identified in the Southern New England Transmission Reliability (SNETR) Report Needs Analysis of January 2008.[14] The SNETR study proposed NEEWS as a regional solution to reliability violations that would limit East-to-West power transfers across southern New England, and interstate power transfers within southern New England.

The general locations of the reliability concerns identified in the SNETR study are shown in Exhibit 1-1, as are the four projects that comprise NEEWS. Each of the four projects includes the installation of a new 345-kV line among other components, and each individually addresses at least one of the reliability concerns that ISO-NE identified. The four projects are designed to be complementary. Therefore, the benefits of the NEEWS projects as a whole exceed those of the four component projects considered individually. The Project is designed specifically to alleviate both thermal and voltage violations and to increase the area's access to the 345-kV bulk transmission system.

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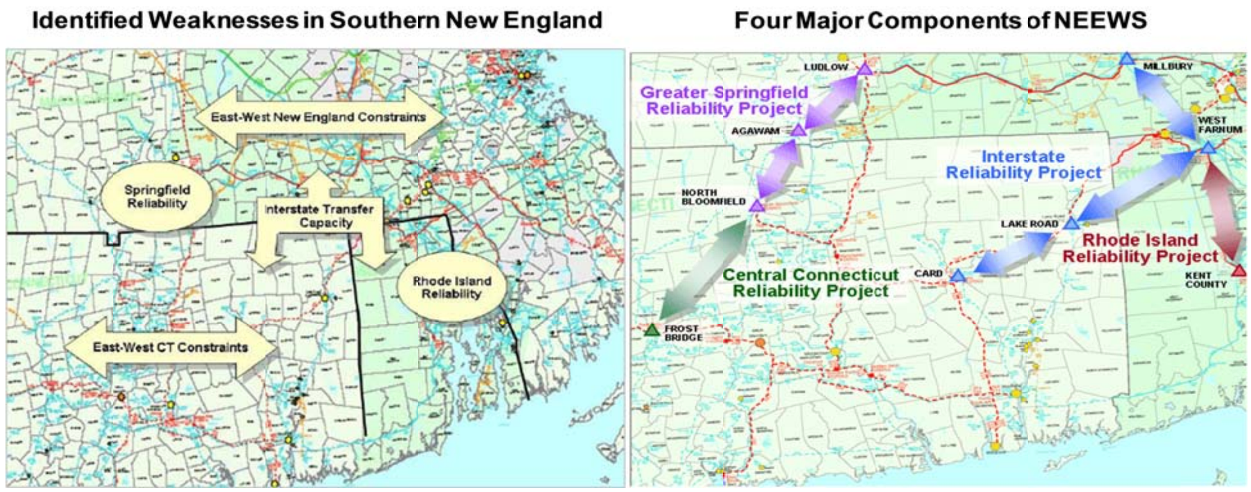
[12] ISO-NE is the regional transmission organization (RTO) serving the New England electricity market.

[13] 2010 Regional System Plan, October 28, 2010, ISO New England, page 81.

[14] Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England.

Exhibit 1-1
Reliability Concerns in Southern New England and Components of NEEWS – SNETR Study



Sources: ISO New England's "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008; and NUSCO web site: http://www.transmission-nu.com/residential/projects/NEEWS/default.asp#

In 2009, ISO-NE reaffirmed the need for Rhode Island Reliability Project and Greater Springfield Reliability Project, and the siting agencies in Rhode Island, Massachusetts and Connecticut recently approved both of these components.

In April 2011, ISO-NE updated the analysis of the transmission improvements required to maintain reliability in southern New England, with a specific focus on the Interstate Reliability Project component of NEEWS[15].

The objective of ISO-NE's 2011 study of the Interstate Project was to determine if the need for the Project still exists under currently forecasted system conditions. The reassessment was necessary due to changes in system conditions since the last needs assessment in 2008, including an updated load forecast in the 2010 RSP, system operating constraints, changes in resources acquired and delisted through the Forward Capacity Auctions (FCA), and the impact of the potential retirement of some generation facilities.[16]

The April 2011 ISO-NE study reaffirmed the need for the Interstate Project to help meet national and regional reliability criteria and serve load throughout southern and eastern New England. It addressed several areas of concern, including:[17]

- Multiple interrelated violations of North American Electric Reliability Corporation (NERC), Northeast Planning Coordinating Council, Inc. (NPCC) and ISO-NE transmission planning standards and criteria in eastern New England, western New England, Greater

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[15] *New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment dated April 2011.*

[16] *2010 Regional System Plan, October 28, 2010, ISO New England, page 5.*

[17] *New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment dated April 2011, page 1.*

Rhode Island and Connecticut that are projected to exist within the 10-year planning horizon.

- The ability to serve load with existing and FCA cleared generation from western New England to eastern New England and from eastern New England to western New England resulting from transmission constraints along the 345 kV transmission corridor from southeast Massachusetts through Rhode Island into eastern Connecticut.

The results of the study reaffirming the need for the Project are described in more detail in the ISO-NE report New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment[18] ("Interstate Updated Needs Assessment Report").

In demonstrating the reliability need for a transmission project, a proponent will usually be required to show that the reliability criteria violations addressed by the project cannot be resolved more cost-effectively and/or with fewer environmental impacts by non-transmission resources such as demand resources (including distributed generation and combined heat and power facilities) and traditional generation supply. ICF International (ICF) was retained by NUSCO and National Grid to assess the potential to develop alternative regional solutions to the reliability violations in southern New England using non-transmission resources such as demand resources (including distributed generation and combined heat and power facilities) and traditional generation supply. The alternative solutions, referred to as Non-Transmission Alternatives (NTA), could displace or defer the project if their performance is comparable to that of the transmission solution.

This report describes ICF's approach for studying the NTA and the results of the study.

1.2 New England Transmission System Reliability

ISO-NE is obligated to meet, at a minimum, the electric industry reliability standards set by NERC, which is the electric reliability standards development and enforcement body for North America. NERC has established rules and criteria for all geographic areas in North America. The performance of the New England transmission system is also governed by reliability standards and criteria established by NPCC and ISO-NE. NPCC is one of eight regional entities under NERC. As the regional entity for northeastern North America (i.e., New England, New York and eastern Canada), NPCC sets specific rules and criteria for the Northeast. ISO-NE has then further developed rules and criteria specific to New England.

The reliability standards address both local concerns (Area Transmission Requirements) and regional concerns (Transmission Transfer Capability). The Area Transmission Requirements specify that the transmission system should be capable of delivering power to consumers under anticipated outage conditions. Transmission Transfer Capability addresses the need for the transmission system to be capable of transferring power within the ISO-NE region and between ISO-NE and its neighbors. The standards define the system conditions and contingencies that must be evaluated when performing a reliability assessment of the transmission grid.[19] These standards were incorporated in ICF's study.

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[18] *New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment, April 2011, Southern New England Regional Working Group, ISO New England.*

[19] *ISO New England Planning Procedure No. 3, Reliability Standards for the New England Area Bulk Power Supply System, October 13, 2006*

As part of its regional transmission planning process, ISO-NE evaluates whether any areas within its footprint or border regions may violate NERC standards within the 10-year planning horizon. ISO-NE carries out its transmission system analyses to assess and address compliance with mandatory NERC Transmission Planning (TPL) standards. The TPL standards require an evaluation of system performance under normal (no outage) and various single and multiple contingency (transmission facility outage) conditions. They also require a demonstration that the transmission system is planned in such a way that it can be operated to meet customer demand at all demand levels over the range of forecast system demands and a variety of representative generator dispatch scenarios, under the different contingency conditions.

As described in the ISO New England 2010 Regional System Plan (2010 RSP), the "main objectives of ISO-NE's regional system planning process are to identify system enhancements required to ensure the reliability of the system, facilitate the efficient operation of the markets, and provide information to regional stakeholders, who can use the information to conduct independent analyses and further develop system improvements. The development of needed supply and demand resources and transmission upgrades supports the reliable operation of the power system for the short and long term. The transmission upgrades also enhance the region's ability to support a robust, competitive wholesale power market by reliably moving power from various internal and external sources to the region's load centers. In addition to meeting regional reliability needs and supporting the markets, additional transmission infrastructure can build a foundation for integrating new resources, including renewables."[20]

Through the planning process, ISO-NE and stakeholders assess the amount and general location of resources that the overall system and individual areas need, and the types of resources that can potentially satisfy the identified need. Stakeholders can use the information on the defined system needs, together with signals from the markets, to assess options for satisfying these needs through merchant transmission upgrades or non-transmission alternatives such as new power plants or programs to reduce electricity demand. These merchant transmission and NTAs could result in modifying, offsetting, or deferring proposed regulated transmission upgrades. However, if stakeholder responses to market signals are inadequate, ISO-NE is obligated to develop regulated transmission solutions that determine transmission infrastructure that can meet the identified needs.[21] ISO-NE performs a Needs Assessment to determine the adequacy of the power system, as a whole or in part, to maintain the reliability of the facilities while promoting the operation of efficient wholesale electric markets in New England.[22]

In the 2010 RSP, ISO-NE highlighted concern over future reliability violations within southern New England. Although system conditions had changed since the last analysis of southern New England, the 2010 ISO New England Capacity, Energy, Load and Transmission (CELT) forecasted load for 2015 was higher than the critical load level[23] included in previous analyses, which showed the reliability violations identified in the original Needs Assessment for NEEWS. [24] It was therefore likely that an updated study would show that reliability violations would persist under the more recent projections of future conditions. This was validated by the April 2011

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[20] *2010 Regional System Plan, October 28, 2010, ISO New England, page 12.*

[21] *2010 Regional System Plan, October 28, 2010, ISO New England, pages 13-14.*

[22] *2010 Regional System Plan, October 28, 2010, ISO New England, page 61.*

[23] *Critical load level refers to the system load at which reliability criteria violations, which show the need for a transmission solution, appear.*

[24] *2010 Regional System Plan, October 28, 2010, ISO New England, page 76.*

Updated Interstate Needs Assessment study. Further, the original need for the Interstate Project was based on limitations on the transfer of power from eastern New England to western New England and to Connecticut. The updated analysis showed that there is also an increased need for the capability to move power from western New England to eastern New England. With increased resources in the west, constraints to the east of the Greater Rhode Island area were more evident.[25]

The 2010 RSP further states, regarding the southern New England transmission system, that "although recent improvements have been made, the southern New England system continues to face thermal, low-voltage, high-voltage, and short-circuit concerns under some system conditions. The most significant concerns involve maintaining the reliability of supply to serve load and developing the transmission infrastructure to integrate generation throughout this area. In many areas, an aging low-capacity 115 kV system has been overtaxed and no longer is able to serve load and support generation reliably."[26]

1.3 Non-Transmission Alternatives

Transmission and distribution systems are designed to provide reliable power delivery from the source to an end-user. As demand for electrical energy grows, utilization of the transmission system also grows and upgrades may be required to continue to serve load reliably over time. Alternatively, additional generation sources nearby the load demand areas, or reductions in the load at key demand areas may alleviate the load on the transmission system and help to defer or displace transmission upgrades that might otherwise be necessary. In assessing the potential for alternative resources to displace or defer the Project, ICF considered options on the demand and supply side:

a) **Demand Resources:** Demand resources represent a large block of options that tend to reduce the demand for system generation and transmission services either through direct reductions in the load, or the addition of distributed generation at the source of the load. The analysis herein considers both active (responsive) and passive (non-responsive) demand resources as an alternate to transmission.

    a. Energy Efficiency: Energy efficiency resources are passive demand resources which result in load reductions through conservation of energy use. Energy efficiency programs typically target increasing efficiency for equipment. Programs may for example replace older less efficient equipment with newer more efficient equipment. The improvement in efficiency means the new equipment will provide the same function with less energy consumption, all else equal. Likewise, an energy efficiency program may provide for more efficient operation of existing equipment through better management or maintenance of that equipment. Following the FCM, passive demand resources are considered to be either on-peak or seasonal.

    b. Distributed Generation: These reflect the resources that would be located at an end-use location and could serve as either a primary or supplementary source of power for that location. Generation produced from these facilities would reduce the overall demand for central generation and hence reduce the demand for transmission services. Distributed generation may be active (dispatchable) or passive (non-dispatchable).

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[25] *2010 Regional System Plan, October 28, 2010, ISO New England, pages 78.*

[26] *2010 Regional System Plan, October 28, 2010, ISO New England, pages 75.*

c. Active Demand Response Resources: Active demand resources are controllable resources that respond to particular indicators such as load levels, dispatch signals, or prices, to activate. These resources are active demand resources.

d. Real-Time Emergency Generation Resources: Emergency generators, like real-time demand resources, are resources which are responsive to a particular event (active resources). Often, an emergency generator is a site specific resource activated in instances of power outages affecting the site and are used for back-up generation.

b) **Generation:** Generation resources located close to the load demand centers may also help reduce the overall load on the transmission system. Local generation sources will help reduce the transmission load provided that they are appropriately sized and that they are operating at the time of need. It should be noted that a generator that is sized too large may have an undesired effect of creating additional constraints in trying to move generation in the opposite direction of traditional flows. Such large resources may impact the overall system directional flows and utilization. Hence, generation resources may alleviate constraints in one area, but they may also create constraints in other areas.

Any of these options individually, or in combination, have the potential in some circumstances to defer or displace the need for upgrades to the existing transmission system while maintaining the same level of reliability.

CHAPTER 2
Overview of Approach

ICF's NTA analysis provides a detailed assessment of the capability of non-transmission resources in southern New England to resolve reliability criteria violations and displace or defer the need for the Interstate Project. Non-transmission resources are supply side or demand side resources that could potentially displace or defer the need for a transmission project.

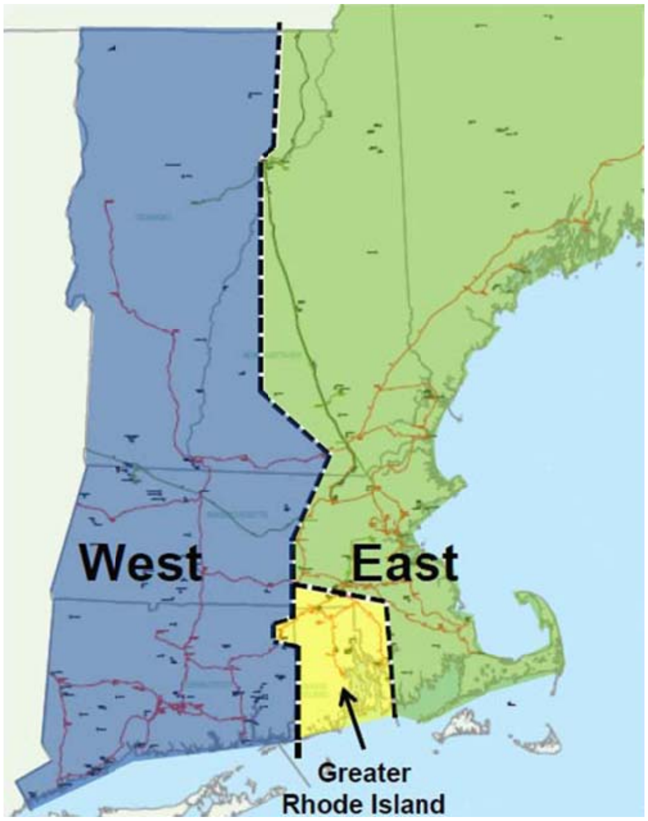
ICF started the analysis with a replication of the results of ISO-NE's Needs Assessment for the Interstate Project. This was necessary in order to verify that ICF's methodology is compatible with that of ISO-NE. After replicating the results of ISO-NE's study, ICF projected the amount of generation and demand side non-transmission resources that could be available in southern New England within the 5 to 10-year planning horizon (2015 and 2020), and then simulated the operation of the New England transmission grid assuming the non-transmission resources were in place. Three NTA options were examined – central generation only, demand side resources only, and a combination of generation and demand side resources. The performance of each NTA option was then compared with that of the Interstate Project. The approach used to conduct the NTA assessments is discussed in more detail in this chapter.

2.1 Transmission System Needs Assessment

As the first step in the assessment of NTAs for the Interstate Project, ICF conducted a study similar to the ISO-NE Needs Assessment study for the Interstate Project and replicated the results of ISO-NE's study. ICF simulated the operation of the New England grid with the assumption that the transmission improvements from the Project are not implemented, and then monitored transmission facilities for potential thermal violations. The model of the New England power market was based on the power flow cases used by ISO-NE in its Needs Assessment study. Similar power flow cases with the Interstate Project in place were used to verify that the Project does indeed resolve the reliability criteria violations.

In the Needs Assessment study, ISO-NE divided the New England transmission system into three sub-regions – Western New England (Western NE), Eastern New England (Eastern NE) and Greater Rhode Island (GRI) – based on weak transmission connections between neighboring sub-regions (see Exhibit 2-1).

Exhibit 2-1
Interstate Needs Assessment Sub-Areas



Source: New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment, April 2011.

ISO-NE created several generation dispatch scenarios, shown in Exhibit 2-2, which stressed selected sub-regions or local areas to assess the load serving capability in the sub-region or local area of interest. The Eastern New England Stress scenario assessed load serving capability in Eastern NE by simulating supply shortage conditions in Eastern NE and stressing the New England West to East transfers to determine the transmission capability needed to serve demand in the east with surplus generation from the west. GRI was considered part of Western NE when assessing the load serving capability of Eastern NE. The Western New England Stress scenario assessed load serving capability in Western NE by simulating supply shortage conditions in Western NE and stressing the New England East to West transfers to determine the transmission capability needed to serve demand in the west with surplus generation from the east. In this case GRI was considered part of Eastern NE. The Western New England Stress scenario was also used to assess load serving capability in Connecticut. Lastly, the Rhode Island Stress dispatch scenario was used to assess load serving capability in Rhode Island. The load serving capability for Rhode Island focused on the Rhode Island load zone, which covers most of the state of Rhode Island, but is smaller than the GRI sub-region. This dispatch scenario stressed conditions in the Rhode Island load zone to determine the capability needed on the transmission system to serve demand in the local area.

ISO-NE developed several power flow cases for each dispatch scenario to analyze the load serving capability for each sub-region for the two study years (2015 and 2020) and under different contingency conditions. ICF simulated the operation of the New England system using the power flow cases developed by ISO-NE, and replicated results that showed the need for Interstate. Taking this step was necessary in order to verify that ICF's methodology is compatible with that of ISO-NE. The replication ensures that ICF's starting point in analyzing violations and potential solutions is the same as ISO-NE's, and that any potential NTAs analyzed by ICF would be tested on the violations identified by ISO-NE. ICF also modeled the Interstate Project in the power flow cases and demonstrated that it provides a regional solution to reliability violations that could occur in these sub-regions under multiple dispatch scenarios.

The approach and results of ICF's Needs Assessment study are discussed in more detail in Chapter 3.

Exhibit 2-2
Dispatch Scenarios Examined

Dispatch Scenario [1]	Purpose	Power Transfers
Eastern New England Stress	Load Serving Capability into Eastern NE	New England West to East
Western New England Stress	Load Serving Capability into Western NE	New England East to West
	Load Serving Capability into CT	
Rhode Island Stress	Load Serving Capability into RI	Into RI

[1] The ISO's analysis also included an Eastern New England Stress dispatch scenario with Salem Harbor assumed to be out of service. ICF's Salem Harbor retirement sensitivity scenario is presented in Chapter 7.

2.2 Critical Load Level Analysis and Assessment of Demand Side Alternatives

Within the context of transmission planning, the critical load level (CLL) reflects the demand level (MW) for the system above which line overloads begin to occur. Above this load level, the transmission system would need to be expanded to continue to support the demand requirement. ISO-NE performed CLL analyses in the 2010 Needs Assessment study for the Vermont/New Hampshire transmission system.[27] In that study ISO-NE determined the CLL for the entire regional system, using a standard load flow technique to test and document system performance under differing load levels until the point at which reliability violations in the Vermont/New Hampshire study area were eliminated. Specifically, ISO-NE prorated all loads in the ISO-NE region downward until the localized Vermont/New Hampshire violations which had been identified at higher loads were eliminated.

ICF used a similar approach to determine a CLL for southern New England. In this case, however, ICF focused on load in the southern New England only, consistent with the goal of the NTA assessment. ICF determined the load level in southern New England at which the identified violations resolved by Interstate begin to occur. This approach showed the amount of demand reduction that would be required to eliminate all of the identified violations resolved by Interstate and the result is a measure of the demand reduction required for a demand-only NTA solution.

[27] *VT/NH Critical Load Level Results and Preliminary Transmission Alternatives Under Consideration, ISO New England Planning Advisory Committee, Feb 17, 2011.*

Specifically, ICF determined the load reductions in Western NE, Eastern NE and Rhode Island required to resolve all the identified violations related to load serving capability in each individual sub-region. The results for the individual sub-regions were then aggregated to determine the demand reduction required to resolve violations in southern New England and calculate the CLL for southern New England. In addition, ICF performed CLL analyses stressing both CT imports and CT exports to determine the load levels at which violations begin to appear. These analyses were undertaken because ISO-NE's Updated Need Assessment identified a specific need for additional transmission transfer capability into Connecticut, as well as a need for transmission transfer capability from West to East.

As an indication of the feasibility of developing an NTA solution from demand resources only, the demand reduction required to achieve the southern New England CLL was compared to the level of demand side resources necessary to achieve that reduction. This included consideration of the potentially achievable passive demand resource as well as the additional required active demand resource needed to achieve an equivalent load reduction.

The estimates of passive and active demand resources were incremental to levels already included in the ISO-NE cases. ISO-NE modeled demand resources from FCA #4 in the power flow cases, which reflected resources expected to be available in the 2013/2014 commitment period. [28] ICF estimated the incremental passive demand resources that would be practically available in the study years, 2015 and 2020. ICF's projections focused on passive demand resources, which are typically utility sponsored (or naturally occurring) programs. Within New England, these programs are subject to regulatory approvals at the state level, and are also frequently backed with state level funding to support utility implementation of programs for consumers. As such, ICF's projections of passive resource levels were based on the demand reduction targets and funding proposed in the state energy efficiency programs for Connecticut, Rhode Island and Massachusetts.

ICF estimated and tested two different levels of demand resources in southern New England:

- **Reference Passive Demand Resource (Reference DR Case)**: This refers to ICF's estimates of passive demand resources that could be achieved for each state if targeted goals for current programs and for expected legislation are achieved at similar levels each year through 2020.
- **Aggressive Passive Demand Resource (Aggressive DR Case)**: This is a more aggressive level of demand resources examined as a sensitivity scenario. This sensitivity considers the potential for passive resources assuming higher, yet reasonably achievable growth in resources occur. It assumes the amount of demand resources that will be available in southern New England will exceed the reference levels by17 percent in 2020.

Exhibit 2-3 summarizes the achievable passive demand resources in each state, which was used as the basis for the demand NTA. A power flow analysis was performed to assess the ability of the demand resources to resolve the reliability criteria violations in southern New England and to develop a demand NTA solution.

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[28] FCA #4 was the most recent Forward Capacity Auction at the start of the updated Interstate Needs Assessment. It was held in August 2010 and it procured resources required to satisfy the New England power market's Installed Capacity Requirements for the 2013/2014 commitment period.

Exhibit 2-3
Achievable Passive DR in Southern New England – 2015 and 2020

Category	Connecticut		Massachusetts		Rhode Island		Total	
	2015	2020	2015	2020	2015	2020	2015	2020
Reference Passive DR (MW)	473	661	770	1,513	128	237	1,371	2,411
Aggressive Passive DR (MW)	495	783	795	1,742	141	306	1,430	2,831

To the extent that the available passive demand resources were not satisfactory to provide an NTA solution, additional active demand resources were required. ICF identified the need for active demand resources required to provide the incremental load reduction required to resolve transmission violations and provide an NTA solution.

The analysis showed that a demand NTA that would solve the identified reliability criteria violations was not practically feasible.

ICF prepared a rough estimate of the capital cost (all-in installation cost) of resources required to develop the NTAs. The methodology and cost assumptions are described in Appendix E.

The approach and results of ICF's CLL Analysis is discussed in more detail in Chapter 4. The approach used to determine the potentially achievable demand resource and the results of the comparison to the CLL are described in Chapter 5.

2.3 Assessment of Generation Alternatives

ICF reviewed the New England Generation Interconnection Queue (Interconnection Queue) as of April 1st, 2011 to identify proposed generation facilities in southern New England that could be used for developing NTAs to the Interstate Reliability Project. An NTA solution could be developed if sufficient generation resources are available in the appropriate locations to resolve the reliability criteria violations observed in the Needs Assessment.

The generation resources available in the Interconnection Queue were grouped into three categories based on the likelihood of construction:

- **Category 1:** Facilities with completed Interconnection Agreements. These facilities have gone through various studies and all the steps in the approval process and were considered very likely to be developed.
- **Category 2:** Facilities with Proposed Plan Application (PPA) approval in accordance with Section I.3.9 of the ISO New England Transmission, Markets and Services Tariff, but excluding facilities with completed Interconnection Agreements (Category 1).
- **Category 3:** All facilities in the Interconnection Queue, but excluding facilities with completed Interconnection Agreements (Category 1) and Section I.3.9 approval (Category 2). Units in Category 3 were considered to have the lowest probability of being developed.

A total of 2,850 MW of proposed generation capacity in southern New England was available from the Interconnection Queue, including 427 MW in Category 1, 1,904 MW in Category 2, and

520 MW in Category 3 (see Exhibit 2-4). Exhibit 2-5 shows the capacity available in each sub-region. Additional detail on generators in the Interconnection Queue is presented in Appendix D.

ICF simulated the operation of the New England power system using the power flow cases developed for the Needs Assessment, but with the assumption that the additional generation resources are available in the study years. The power flows on transmission facilities in southern New England were monitored for thermal violations to assess the ability of the additional generation resources to resolve the reliability criteria violations and develop a generation-only NTA solution.

ICF did not find a practically feasible generation NTA that solved the identified reliability criteria violations. The generation NTA reduced the number of elements overloaded and the number of violations, but many of the most severe overloads still remained.

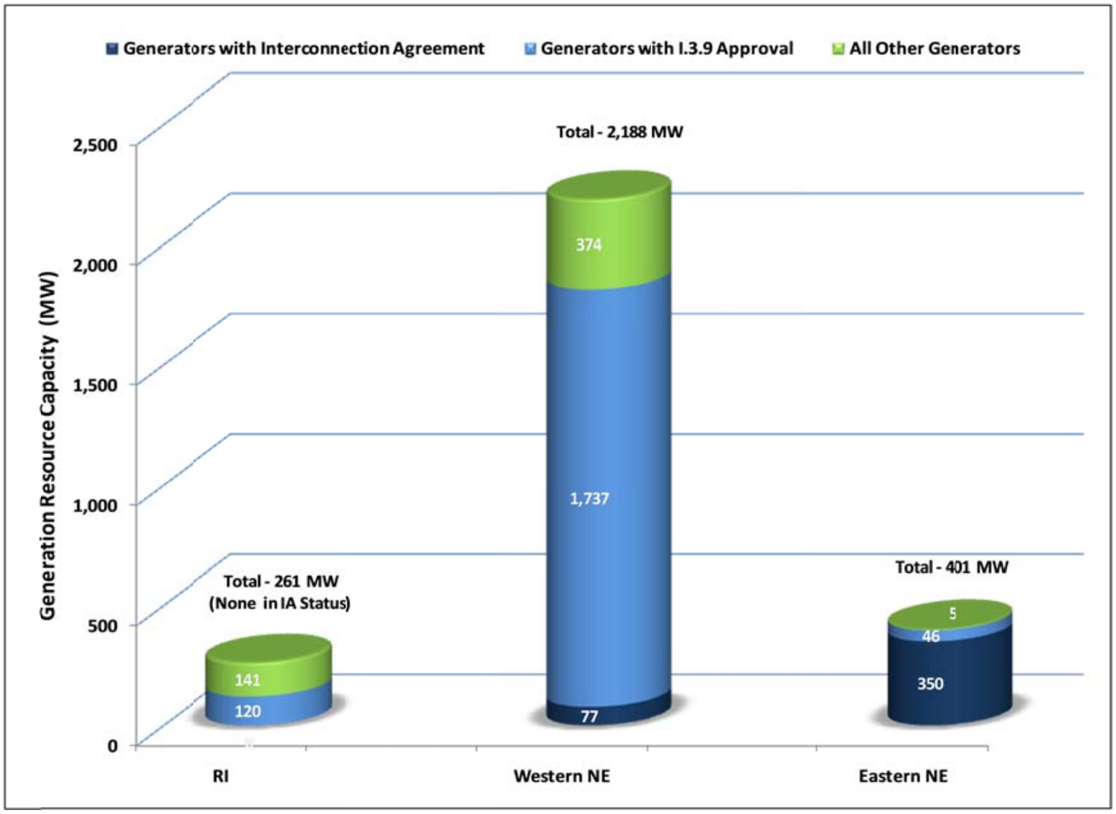
The approach and results of ICF's generation NTA analyses are discussed in more detail in Chapter 6.

Exhibit 2-4
Potential NTA Generation in Southern New England

Category	Description	Capacity (MW)
Category 1	Generators with completed Interconnection Agreements	427
Category 2	Generators with I.3.9 approval (excluding Category 1)	1,904
Category 3	All generators in the Interconnection Queue (excluding Categories 1 and 2)	520
Total		**2,850**

Source: ISO New England Generation Interconnection Queue as of April 1, 2011.

Exhibit 2-5
Potential NTA Generation Capacity in Southern New England



Source: ISO New England Generation Interconnection Queue as of April 1, 2011.

2.4 Assessment of Combined Generation and Demand Side Alternatives

Following the assessment of generation resources as potential NTAs, ICF considered an expanded NTA that included both demand and generation resources. This was done in several steps. First, ICF developed a combination NTA with the potential passive demand resources discussed above, and generation resources identified from the ISO-NE Interconnection Queue. Load flow analysis demonstrated that violations of thermal criteria would continue to exist following the implementation of this combination generation and passive demand resource NTA. Next, ICF identified the additional level of active demand resources needed to provide an NTA solution that would resolve all the violations that Interstate addresses. The combination of generation, passive demand resources, and active demand resources was then evaluated for feasibility and reasonableness of the solution.

The estimates of passive and active demand resources were incremental to levels already included in the ISO-NE cases. ISO-NE modeled demand resources from FCA #4 in the power flow cases, which reflected resources expected to be available in the 2013/2014 commitment period.[29] Similar to the demand NTA, ICF tested two levels of passive demand resources using the Reference DR Case and the Aggressive DR Case. A power flow analysis was performed to assess the ability of the combination of generation and demand resources to resolve the reliability criteria violations in southern New England and to develop a combination NTA solution.

To the extent that the combination of passive demand resources and available generation were not satisfactory to provide an NTA solution, additional active demand resources were required. ICF identified the need for active demand resources required to provide the incremental load reduction needed to resolve transmission violations and produce an NTA solution.

ICF also prepared a rough estimate of the capital cost (all-in installation cost) of resources required to develop the NTAs. The methodology and cost assumptions are described in Appendix E.

ICF did not find a practically feasible NTA from a combination of generation and demand resources that solved the identified reliability criteria violations.

The approach and results of ICF's combination NTA analysis are discussed in more detail in Chapter 7.

[29] *FCA #4 was the most recent Forward Capacity Auction at the start of the updated Interstate Needs Assessment. It was held in August 2010 and it procured resources required to satisfy the New England power market's Installed Capacity Requirements for the 2013/2014 commitment period.*

CHAPTER 3
Needs Assessment

This chapter describes ICF's replication of the results of ISO-NE's Needs Assessment for the Interstate Project. The replication of ISO's results was the first step in ICF's assessment of non-transmission alternatives to the Project, and taking this step was necessary in order to verify that ICF's methodology is compatible with that of ISO-NE. The replication ensures that ICF's starting point in analyzing violations and potential solutions is the same as ISO-NE's, and that any potential NTAs analyzed by ICF would be tested on the violations identified by ISO-NE. ICF used the 2015 and 2020 power flow cases used by ISO-NE in its assessment of needs.

ICF replicated the results of the need assessment by simulating the operation of the New England grid assuming the transmission improvements are not implemented and monitoring transmission facilities for thermal violations. In order to do this, ICF first constructed a model of the New England transmission system with ICF's PSLF software and confirmed that it agreed with the ISO-NE PSS/E software model used in the ISO-NE Interstate studies. After demonstrating the need for transmission improvements using the same assumptions as those used in the ISO-NE studies, ICF assessed the reliability benefits of the Interstate Project by simulating the operation of the New England grid with the Project in service and verifying that the Project would resolve the reliability criteria violations in 2015 and 2020. For each of these simulations, ICF confirmed that its assumptions and results agreed with those of the ISO-NE analysis.

This chapter is divided into three sections. The first section of this chapter describes the scenarios examined, a summary of the key input assumptions, and the approach used to conduct the power flow analysis. The second section discusses the results of the analysis, and the third section provides a brief conclusion and key findings.

3.1 Methodology and Rationale

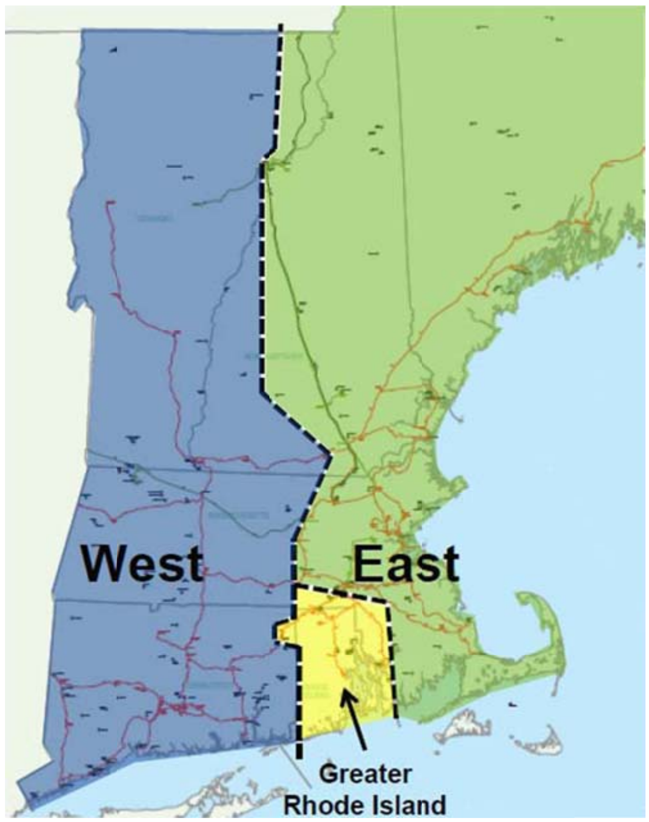
Assessing the reliability-based transmission needs in southern New England is challenging for several reasons. First, the reliability violations affect the regional operation of the entire New England grid, and they cover a broad geographic scope. Second, transmission system studies of this nature require detailed engineering assessments using non-linear power flow models of the transmission system. Third, multiple scenarios are required to assess different operational conditions to ensure that the performance of the transmission system is robust. Scenarios may include variations in interface flow assumptions and primary resource operational assumptions. Fourth, multiple load flow cases are required for different years and contingencies.

3.1.1 <u>Dispatch Scenarios and Scope of Violations</u>

In its needs assessment study, ISO-NE divided the New England transmission system into three sub-regions based on weak transmission connections between neighboring sub-regions. The three sub-regions, Western NE, Eastern NE and GRI are shown in Exhibit 3-1. ICF's transmission analysis focused on southern New England, comprising the states of Connecticut, Massachusetts, and Rhode Island. Therefore, in this report, the terms "Western NE" and "Eastern NE" will refer primarily to the southern New England parts of the sub-regions in Exhibit 3-1. These three sub-regions can be described by state and load zone (see Exhibit 3-2) as follows:

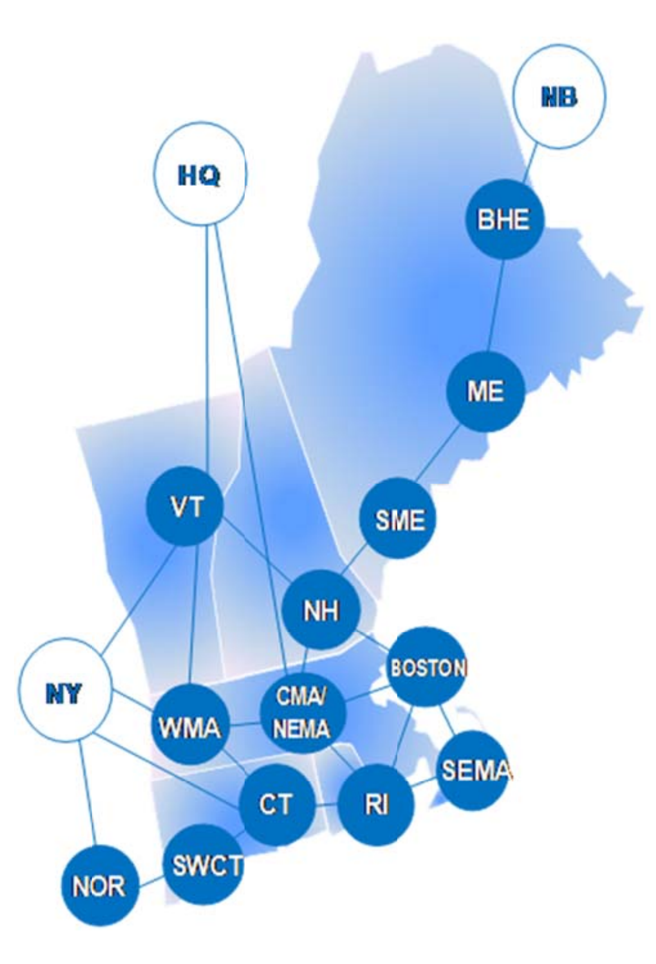
- Western NE – Encompasses the load zones in Connecticut and western Massachusetts, and including most or all of the Norwalk (NOR), Southwest Connecticut (SWCT), and Rest of Connecticut (CT) load zones in Connecticut and the Western Massachusetts (WMA) load zone in western Massachusetts.
- Eastern NE – Encompasses the load zones in eastern Massachusetts, including most or all of the Boston, Central Massachusetts/Northeast Massachusetts (CMA/NEMA) and Southeast Massachusetts (SEMA) load zones.
- Greater Rhode Island – Encompasses primarily the state of Rhode Island, but includes portions of Connecticut and Massachusetts that are electrically considered part of Rhode Island due to transmission constraints.

Exhibit 3-1
Interstate Needs Assessment Sub-Areas



Source: New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment, April 2011.

Exhibit 3-2
Geographic Scope of the New England Electric Power System



Subarea Designation	Region or State
BHE	Northeastern Maine
ME	Western and central Maine/ Saco Valley, New Hampshire
SME	Southeastern Maine
NH	Northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine
VT	Vermont/southwestern New Hampshire
BOSTON (all capitalized)	Greater Boston, including the North Shore
CMA/NEMA	Central Massachusetts/ northeastern Massachusetts
WMA	Western Massachusetts
SEMA	Southeastern Massachusetts/ Newport, Rhode Island
RI	Rhode Island/bordering Massachusetts
CT	Northern and eastern Connecticut
SWCT	Southwestern Connecticut
NOR	Norwalk/Stamford, Connecticut
NB, HQ, and NY	New Brunswick (Maritimes), Hydro Québec, and New York external balancing authority areas

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 20.

ISO-NE created several generation dispatch scenarios that stressed selected sub-regions or local areas to assess the load serving capability in the sub-region or local area of interest. Each dispatch scenario and the corresponding area(s) of interest are shown in Exhibit 3-3. To assess load serving capability in Eastern NE, ISO-NE used a dispatch scenario that simulated supply shortage conditions in Eastern NE and stressed the New England West to East transfers to determine the transmission capability needed on the bulk transmission system to serve demand in the east with surplus generation from the west. Similarly, to assess load serving capability in Western NE, ISO-NE used a dispatch scenario that simulated supply shortage conditions in Western NE and stressed the New England East to West transfers to determine the transmission capability needed on the bulk transmission system to serve demand in the west with surplus generation from the east. A similar dispatch scenario was used to assess load serving capability in Connecticut. Lastly, the dispatch scenario used to assess load serving capability in Rhode Island stressed conditions in the Rhode Island load zone to determine the capability needed on the transmission system to serve demand in the local area.

Exhibit 3-3
Dispatch Scenarios Examined

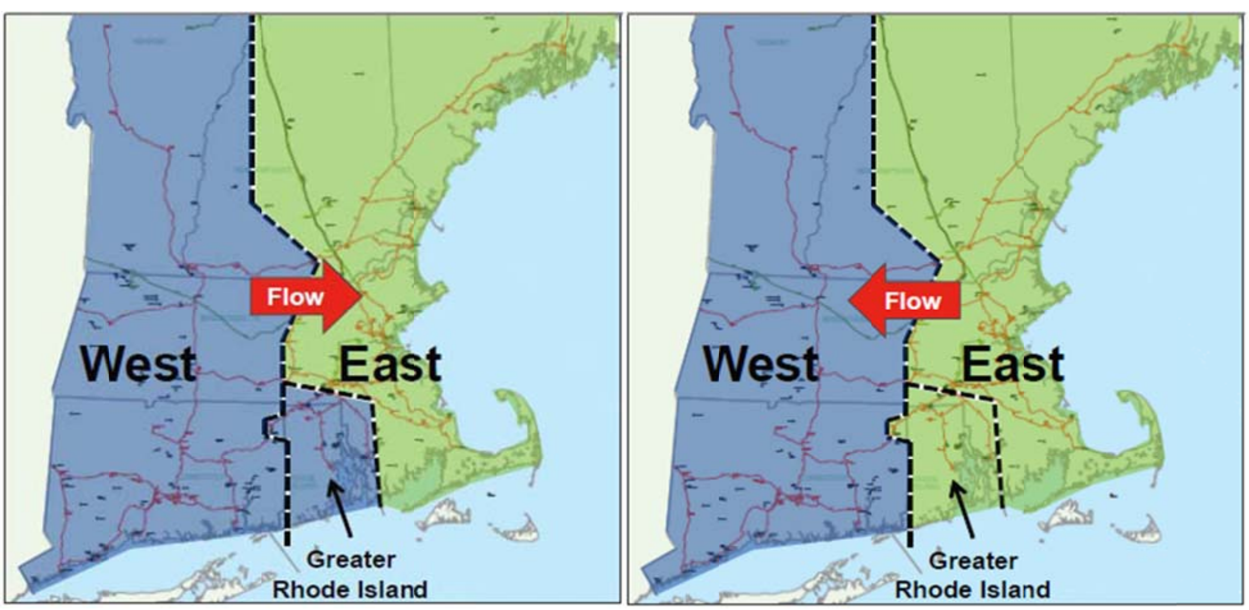
Dispatch Scenario [1]	Purpose	Power Transfers
Eastern New England Stress	Load Serving Capability into Eastern NE	New England West to East
Western New England Stress	Load Serving Capability into Western NE	New England East to West
	Load Serving Capability into CT	
Rhode Island Stress	Load Serving Capability into RI	Into RI

[1] The ISO's analysis also included an Eastern New England Stress dispatch scenario with Salem Harbor assumed to be out of service. ICF's Salem Harbor retirement sensitivity scenario is presented in Chapter 7.

Exhibit 3-4 shows the two system configurations used to assess load serving capability in Western NE and Eastern NE. The diagram to the left shows that GRI was considered part of Western NE when assessing load serving capability in Eastern NE. When moving power eastward from sub-regions in the west with surplus generation to serve load in sub-regions in the east that are experiencing a shortage, generation in GRI is constrained to the east of the GRI sub-region. Under such conditions GRI is electrically part of the western area.

The diagram to the right in Exhibit 3-4 shows that GRI was considered part of Eastern NE when assessing load serving capability in Western NE. When moving power from east to west to serve load in western sub-regions that are experiencing a shortage, generation in GRI is constrained to the west of the sub-region. Therefore, GRI becomes electrically part of the eastern area.

Exhibit 3-4
Eastern and Western New England Sub-Areas by Direction of Power Flow



Source: New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment, April 2011.

The load serving capability assessments for Rhode Island and Connecticut focused on the load zones within each state. The study areas used are shown in Exhibits 3-5 and 3-6. Notably, the study area for the Rhode Island load serving capability assessment is the Rhode Island Load Zone and not the entire Greater Rhode Island sub-region. The Rhode Island Load Zone covers most of the state of Rhode Island, but is smaller than the GRI sub-region. As shown in Exhibit 3-5, the Rhode Island Load Zone is comprised of the loads served by substations within the state of Rhode Island, but excluding the Rhode Island loads served by substations in the southeastern part of the state (which are electrically remote). It also includes the Massachusetts loads that are served by substations located along Rhode Islands' eastern border (which are electrically close). The load serving capability assessment for Connecticut focused on the three load zones in Connecticut: NOR, CT and SWCT. As shown in Exhibit 3-6, the Connecticut study area covers most of the state of Connecticut.

The power flow cases used for the load serving capability analyses are described in the next section. To avoid confusion, the term "scenario" will be used broadly to describe the system conditions that were analyzed, while the term "case" will be used to describe the specific power flow data used to analyze various aspects of the scenarios. For example, the Eastern NE stressed dispatch scenario was used in analyzing load serving capability in the Eastern NE sub-region. However, as will be discussed in the next sub-section, several power flow cases were developed for this dispatch scenario because the load serving capability assessment for Eastern NE was conducted for different study years and different contingency conditions.

Exhibit 3-5
Study Area for Rhode Island Load Serving Capability Assessment

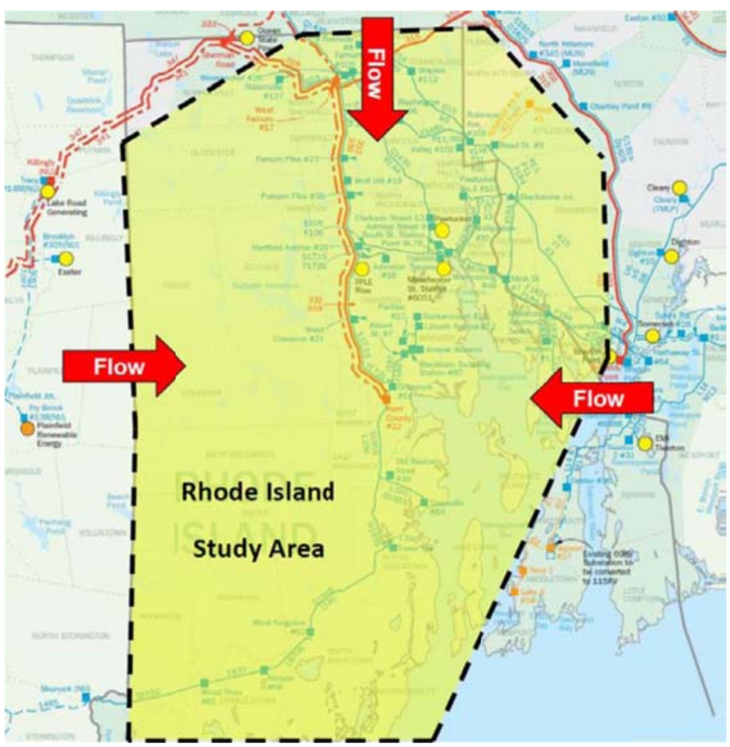
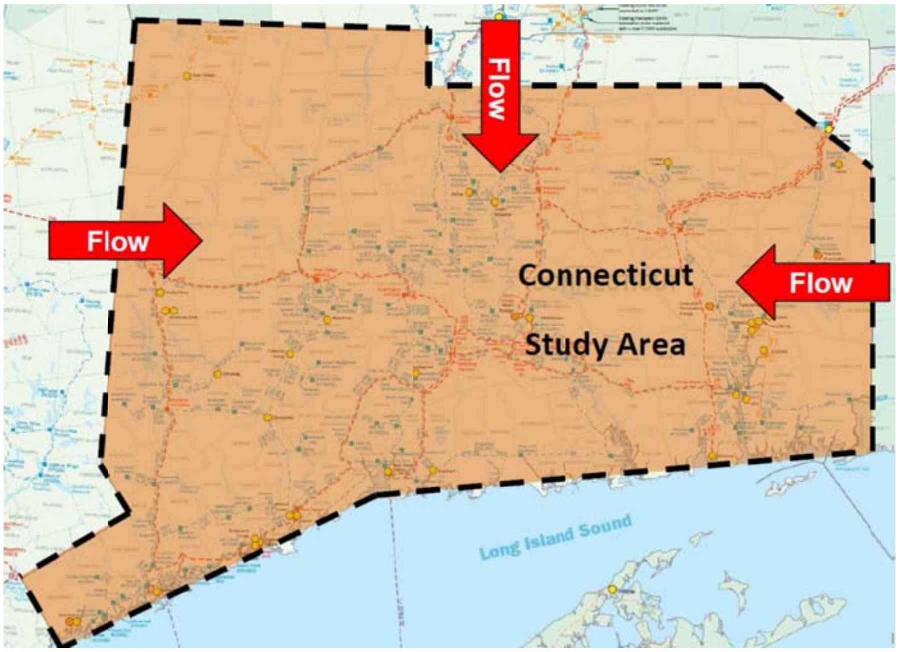


Exhibit 3-6
Study Area for Connecticut Load Serving Capability Assessment



3.1.2 Cases Modeled

The base power flow cases used in performing the load serving capability assessment for the sub-regions and local areas are described in Appendix A. ICF used 8 power flow cases developed by ISO-NE for use in its needs assessment study. Each base case was subjected to contingencies defined by NERC, NPCC and ISO standards and criteria, including the loss of a single transmission circuit, transformer, or bus section and also the loss of multiple elements that might result from a single event such as a circuit breaker failure or loss of two circuits on a multiple-circuit tower. The loss of a single transmission element is referred to as an N-1 contingency. The loss of a single transmission element followed by the loss of a second element is referred to as an N-1-1 contingency.

3.1.3 Summary of Assumptions

ISO-NE based the 5-year and 10-year projections of system conditions on the ISO New England 2010-2019 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) issued in April 2010, the most recently available report at the time of the study. Other assumptions were incorporated to reflect conditions in the study years and in the study area of interest. The assumptions were consistent with ISO New England Planning Procedure No. 3 (PP3). Below is a summary of some of the key assumptions ISO-NE used in developing the base power flow cases. More detailed assumptions are available in Section 3 of the Interstate Updated Needs Assessment Report.

- **Demand**

  The study used projected 2015 peak demand levels for the five-year horizon and 2020 peak demand levels for the ten-year horizon from the 2010 CELT report. Since the 2010 CELT report has forecasts up to 2019, the growth rate from 2018 to 2019 was applied to the demand for 2019 to estimate the 2020 load. The 2015 summer peak 90/10 demand forecast for New England was 31,810 MW. The 2020 summer peak 90/10 demand forecast was 33,555 MW. Because the CELT forecast of demand includes estimated transmission losses, the value was reduced to avoid "double counting" for transmission losses in the power flow simulation.[30]

- **Generation Facilities**

  All generation projects that cleared FCA #4 (for delivery year June 1, 2013 to May 31, 2014), with a firm capacity supply obligation, were included in the base power flow cases.

  The Vermont Yankee nuclear power generating station was considered out of service in the analyses. There is significant uncertainty surrounding the continued operation of the plant because its operating license is due to expire in March 2012. To ensure that the New England transmission system will be robust enough to operate reliably in the event of a permanent shutdown of the station, ISO-NE considered it offline.

  Northfield Station and Bear Swamp Station are two major pumped-storage hydroelectric facilities in New England. They were both de-rated to 50 percent of their capacity to account for potential output limitations during a peak summer day. The output limitations could be caused by unavailability of generation resources to complete pumping operations during off-peak hours, maintaining operating reserves for New England, acceptance of export delist bids for Bear Swamp to serve capacity obligations in New York, and run time limitations to effectively serve New England capacity needs over long-time emergency periods (12 hours for New England in the summer time).

  An unavailability rate of 20 percent was assumed for all quick-start resources in the area of interest, because these units do not always respond when dispatched, due to infrequent use.

  The Salem Harbor generators were assumed to be in service throughout the planning period. Recently, the owner of the Salem Harbor generators has indicated its intention to retire the Salem Harbor units by summer, 2014 and ISO-NE has directed Transmission Owners to assume that Salem Harbor is out of service in all needs analyses of the system from 2014 forward. Therefore, ICF analyzed a sensitivity scenario in which the Salem Harbor power plant was retired.

[30] *The CELT forecast "grosses up" predicted customer demands by adding in average system-wide transmission and distribution losses, to arrive at the load that must be served by available resources. In the power flow model, the predicted load is modeled at the distribution substation level. Transmission losses are then calculated by the model, based on the specific power flows resulting from the specific system configuration and contingencies being modeled. The total resources needed to serve the load will equal the sum of the loads at the substation busses plus the calculated losses.*

- **Dispatch Conditions**

  As described in Exhibit 3-7, dispatch conditions were created to stress each of the areas of interest. In each case the two largest generating units or supply sources in the area of interest were assumed to be out of service. See Appendix A.

- **Demand Resources**

  Demand resources are split into two major categories, passive demand resources and active demand resources. Passive demand resources are largely comprised of Energy Efficiency ("EE") programs and are expected to lower the system demand during designated peak hours in the summer and winter. Active demand resources are comprised of controllable resources, including voluntary load interruption programs that can be dispatched if a forecasted or real-time capacity shortage occurs on the system. Demand resources are modeled in the base case at the levels of the most recent FCA per Attachment K of the ISO New England Tariff. This study used active and passive demand resource values from FCA #4. Active and passive demand resources were modeled as capacity at the load bus in the power-flow model. Active and passive demand resources values were therefore increased to account for the reduction in losses on the local distribution network.

- **Transmission Facilities**

  Transmission projects with Proposed Plan Application approval in accordance with Section I.3.9 of the ISO New England Transmission, Markets and Services Tariff as of the June 2010 RSP Project Listing were included in the base power flow cases. These included Rhode Island Reliability Project and Greater Springfield Reliability Project.

3.1.4 Power Flow Modeling Methodology

Power-flow studies are important in the operation and planning of the transmission grid. The studies are based on detailed models of the power system, including representations of generation units, load, transmission facilities, substations and other components. Computer simulations using powerful software models are then used to determine the performance of the system under various conditions. The results of such simulations include power flows or loading on transmission lines, dispatch of generation units, and voltages at substations. Power-flow simulations can be used to analyze variations in system performance due to changes in configuration. For example, in ICF's study, simulations were used to determine how the power flowing on transmission lines would change if other key transmission lines were taken out of service.

ICF's study was designed to test the operation of the New England transmission system under the ISO-NE standards and criteria, which require that the system reliably continue to serve its load during anticipated transmission facility outages. The standards and criteria also require that the New England transmission system maintain adequate capability to transfer power within New England and between New England and neighboring markets.

The assessment of transmission needs in southern New England was carried out by evaluating the performance of the New England regional transmission system in 2015 and 2020 under forecasted conditions assuming the Project is not implemented. ICF used power-flow models of the New England transmission system developed by ISO-NE for its Needs Assessment studies. These power flow cases were representative of summer peak demand periods in 2015 and

2020. Different dispatch conditions were modeled to simulate load serving capability in each of the three sub-regions – Western NE, Eastern NE and Rhode Island.

To determine the ability of the system to continue to serve its load during anticipated facility outages, ICF performed a detailed power-flow analysis of the system under both N-1 and N-1-1 contingency conditions. Specifically, ICF first assessed system performance assuming the unexpected failure of a key transmission element (N-1) such as a transmission line, a transformer, a circuit breaker, or a pair of transmission lines on a multiple circuit transmission tower. Next, ICF conducted a similar analysis to evaluate system performance following the outage of a single transmission element, followed shortly thereafter by a second element (N-1-1). In this analysis, transmission system operators were assumed to adjust the flows of power following the single element loss.

System performance was measured by monitoring transmission lines for overloads. To continue to operate reliably, the power flowing on each transmission line should remain below the appropriate ratings of the line. In ICF's N-1 and N-1-1 contingency analyses, the power flowing on each line was compared to the long-term emergency limit (LTE) of the line. If a line exceeds its limit, operator action may be taken to relieve the overload; if the overload persists, protective devices in the network may activate to take the line out of service to prevent damage to the line. Emergency actions taken by operators or automatic measures to relieve one line's overload could overload other transmission system elements, worsen system conditions, and result in severe power outages or a blackout. It is therefore important to ensure that the system is designed to operate within limits under anticipated emergencies. Similarly, substation voltages must remain within acceptable limits specified by the operator.

ICF benchmarked its results to that of ISO-NE and verified that its power flow analyses replicated the reliability criteria violations identified by ISO-NE in the Interstate Project Needs Assessment. Specifically, ICF compared its line flows and line overloads to the results from the ISO-NE Needs Assessment study and verified that for all cases modeled, the line loadings on at least 95 percent of the monitored elements were within a 5 percent tolerance band of the respective values recorded in the ISO-NE study.

ICF also conducted a similar detailed power flow analysis to verify that the Interstate Project would resolve all the identified reliability criteria violations and provide a regional solution. To demonstrate the reliability benefits of the Project, ICF evaluated the performance of the New England regional transmission system in 2015 and 2020 under forecasted conditions assuming the Project was implemented. ICF used power-flow models of the New England transmission system similar to the Needs Assessment cases, but with the Project in service. ICF performed a detailed power-flow analysis of the system assuming both normal and contingency conditions. Different dispatch conditions were modeled to evaluate the performance of the Project for load serving capability in each of the three sub-regions – Western NE, Eastern NE and Rhode Island.

3.2 Results

Exhibit 3-7 provides a summary of the results of the Needs Assessment without Interstate and with Interstate in service. It shows the number of reliability criteria violations that occurred in southern New England in 2015 and 2020 under N-1 and N-1-1 contingency conditions in both cases. The table also shows the number of transmission elements on which the violations occurred. ICF's analysis of the base power flow cases shows that reliability criteria violations will occur in southern New England under N-1 and N-1-1 contingency conditions within the 5-year and 10-year timeframes if the Interstate Project is not implemented.

Exhibit 3-7
Summary of Reliability Criteria Violations from Needs Assessment

Status of Interstate	Year	N-1 Contingency Analysis		N-1-1 Contingency Analysis	
		Number of Thermal Violations	Number of Overloaded Elements	Number of Thermal Violations	Number of Overloaded Elements
Interstate Not In Service	2015	0	0	206	20
	2020	12	8	6,029	53
Interstate In Service	2015	0	0	0	0
	2020	0	0	0	0

Under N-1 contingency conditions no reliability criteria violations occurred in 2015. However, ICF observed 12 thermal violations on 8 transmission elements in 2020. Multiple violations could occur on the same element as a result of different contingencies.

Under N-1-1 contingency conditions 206 thermal violations were observed in 2015. In 2020, the number of violations increases significantly to 6,029. These include multiple violations on the same element as a result of different contingencies. In 2015, 20 different transmission facilities are overloaded. This means that in 2015 multiple contingencies cause 206 violations on 20 facilities. The number of elements is 53 in 2020. Therefore, multiple contingencies cause 6,029 violations on 53 facilities.

The extent of the problem in southern New England is evident from the results of the N-1-1 contingency analysis. First, the scale of the problem is large. In 2015, 20 transmission facilities experience thermal overloads following an N-1-1 contingency; this number rises to 53 in 2020. The thermal violations on these elements are caused by multiple contingencies, an indication that there are numerous scenarios under which the violations could occur. Second, the violations occur over a broad geographic scope. Transmission facilities in Connecticut, Massachusetts and Rhode Island are all affected. As a result, an NTA solution to the reliability problems will likely need to be dispersed across all of southern New England.

ICF's N-1 and N-1-1 contingency analyses on the power flow cases with the Interstate Project implemented showed that Interstate resolves the violations identified in Section 5.2 of the ISO-NE Needs Assessment, which are due to constraints in moving power from east to west and west to east in southern New England. All the identified transmission facility loadings were below their limits. Therefore, Interstate resolves the identified thermal violations in 2015 and 2020.

See Section I of Appendix B for a detailed list of the transmission facilities that experienced thermal overloads.

3.3 Conclusion

A comparison of the ICF and ISO-NE results showed that ICF's modeling approach, input data, and results were reasonable.

The analysis also indicated a large number of thermal violations spread across numerous locations. As a result, an NTA solution to the reliability problems will likely need to be dispersed across all of southern New England.

In 2015, 206 thermal overloads were identified at 20 system elements. By 2020, 6,029 thermal overloads were identified at 53 system elements. In some cases, the violations were substantially above the thermal limits of system elements. This is especially true in 2020, under N-1-1 contingency conditions. The thermal overloads on each element could be caused by multiple contingency conditions, indicating that contingencies could occur under numerous scenarios.

Finally, ICF's analysis confirmed that implementation of the Interstate project would eliminate all identified thermal violations.

CHAPTER 4
Critical Load Level Analysis

Like many mechanical structures such as bridges, elevators, and buildings, a transmission system has a 'critical load level' or failure point at which the system can no longer reliably support the demands placed on it. Within the context of transmission planning, the CLL reflects the demand level for the system at which line overloads begin to occur. Above this load level, the transmission system would need to be expanded to continue to support the demand requirement, all else equal.

In the 2010 assessment of needs for the Vermont/New Hampshire transmission system ISO-NE determined the CLL for the New England system load.[31] The critical load milestone analysis in that study used a standard load flow technique to test and document system performance under differing load levels until the point at which no reliability violations were identified. In that assessment, all loads in ISO-NE were prorated downward until the localized Vermont/New Hampshire violations which had been identified at higher loads were eliminated. ICF used a similar approach, focused on load in southern New England only, to determine the load level in southern New England at which the identified violations resolved by Interstate begin to occur. ICF's approach is consistent with the goal of the NTA assessment, and it showed the amount of demand reduction that would be required to eliminate all of the identified violations resolved by Interstate. The result is a measure of the demand reduction required for a demand-only NTA solution.

As described in Chapter 3, the Needs Assessment examined the violations related to load serving capability in Eastern NE, Western NE, and Rhode Island. Similarly, ICF determined the load reduction in each sub-region required to resolve violations related to load serving capability in that sub-region. The results for the individual sub-regions were then aggregated to determine the demand reduction required to resolve violations in southern New England and calculate the CLL for southern New England.[32]

ICF also performed a CLL analysis focused on Connecticut imports and exports to determine the load levels at which violations begin to appear. The analysis was necessary to identify and address issues specific to Connecticut that can affect the regional operation of the grid. For example, some reliability criteria violations in Connecticut that constrain east to west and west to east power flows in southern New England can only be relieved by resources located inside the Connecticut study area and not elsewhere in Western NE. It was not necessary to include the Connecticut CLL separately in the aggregation to determine the Southern New England CLL because Connecticut was included as an integral part in the Western NE and Eastern NE analyses.

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[31] *VT/NH Critical Load Level Results and Preliminary Transmission Alternatives Under Consideration, ISO New England Planning Advisory Committee, Feb 17, 2011.*

[32] *ICF's approach provides a measure of the CLL at the sub-regional level, that is, the sub-regional load at which violations begin to occur. In the Vermont/New Hampshire study ISO-NE calculated the CLL at the system level, that is, the New England load level at which violations begin to occur.*

4.1 Critical Load Level Analysis Methodology

For each of the power flow cases ICF started with scenarios in which thermal violations were present in southern New England, scaled down load in steps and retested key generation dispatches and contingencies at each step until the load reached a level at which power flows ceased to be in violation of the thermal reliability criteria. The load was scaled down only in the sub-region in which load serving capability was being assessed. For example, to estimate the Rhode Island CLL, ICF started with the ISO power flow cases developed to assess load serving capability in Rhode Island. ICF then scaled down Rhode Island load in steps, leaving load in other areas constant. After each load reduction, ICF re-dispatched generation, tested the set of contingencies, and monitored power flows for thermal violations in Rhode Island. This methodology was repeated until the load level at which all identified thermal violations were resolved. ICF used this approach to estimate sub-regional CLLs for Western NE, Eastern NE, and Rhode Island.

ICF also conducted CLL analyses focused on Connecticut to determine the load levels at which violations in Connecticut appear. Based on the Needs Assessment, ICF treated Connecticut as both an importing zone and an exporting zone for the purposes of the CLL analyses. When analyzing Connecticut as an importing zone (east to west transfers), ICF used the ISO-NE power flow case developed for the assessment of load serving capability in Western NE. This analysis is a subset of the Western NE CLL analysis. ICF implemented load reductions and monitored thermal violations only in Connecticut. The result is the Connecticut load level at which violations start to appear in Connecticut when it is operating as an importing zone. When analyzing Connecticut as an exporting zone (west to east transfers), ICF used the ISO-NE power flow case developed for the assessment of load serving capability in Eastern NE. This analysis is a subset of the Eastern NE CLL analysis. ICF implemented load reductions in Eastern NE, but monitored thermal violations only in Connecticut. The result is the Eastern NE load level at which violations start to appear in Connecticut when Connecticut is operating as an exporting zone.

The Western NE CLL, Eastern NE CLL and Rhode Island CLL were then aggregated to obtain the Southern New England CLL associated with the Interstate Reliability Project. The aggregation is performed to provide a representative value for the southern New England area assuming that the dispatch scenarios are considered mutually exclusive. That is, the dispatch scenarios are structured to identify the violations under specific import/export conditions, and load reductions were targeted to each sub-region to resolve violations specifically in that sub-region. This resulted in the minimum reductions required in each sub-region, and a conservative estimate of the reduction required for southern New England. Hence, the sum of the three cases can be interpreted as a conservative estimate of the load level in southern New England at which the need for the Interstate Project appears.

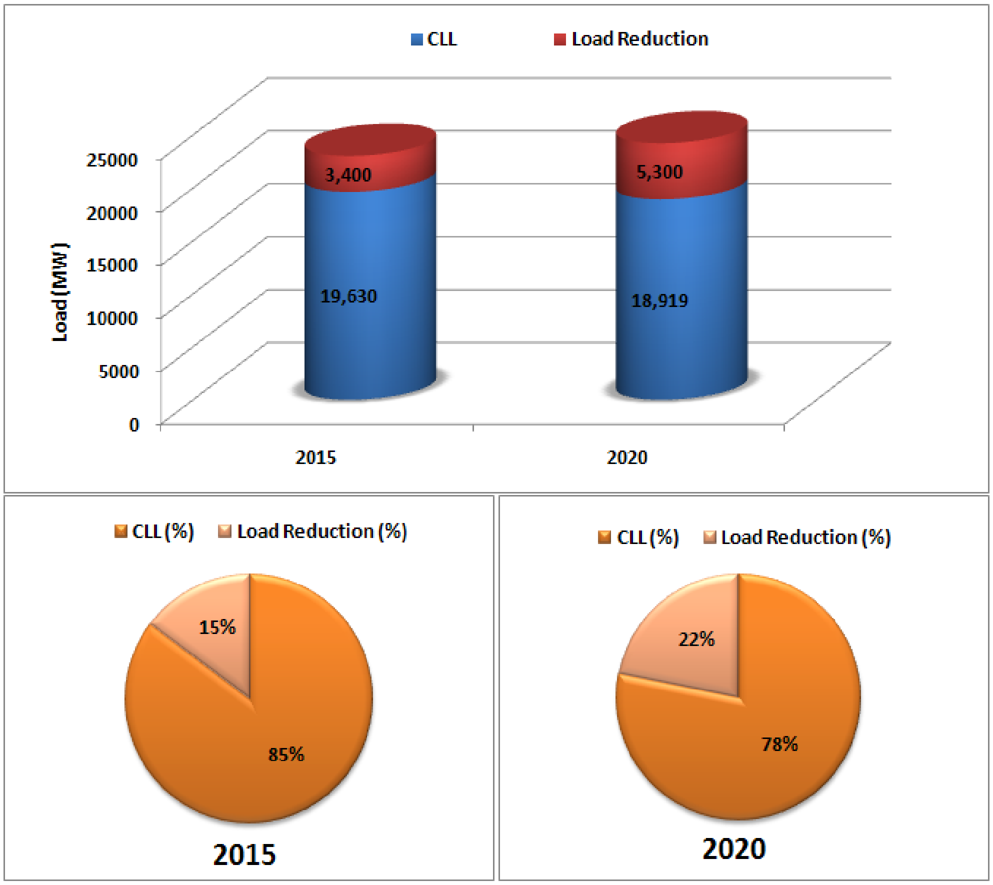
4.2 Results of CLL Analysis

Exhibit 4-1 summarizes the results of the CLL analysis for southern New England for 2015 and 2020, derived by aggregating the CLLs for the component sub-regions. It shows the magnitude of load reductions required to eliminate thermal violations in the monitored area and the resulting CLL. It also shows the load reduction and CLL as percentages of the total load in southern New England. As shown, the Southern New England CLL in 2015 is 19,630 MW, which is approximately 85 percent of the total expected load of 23,030 MW.[33] This means that a

[33] *The percentages are based on 90/10 forecast load levels.*

load reduction of approximately 3,400 MW or 15 percent of the total load considered in the transmission planning exercise will be required to resolve all violations in southern New England. In 2020 the required load reduction increases to 5,300 MW, or 22 percent of the total load of 24,219 MW projected in southern New England.

Exhibit 4-1
Southern New England CLL – 2015 and 2020



A summary of the results of the CLL analysis for the sub-regions is shown in Exhibit 4-2. An examination of these results shows that dramatic load reductions are required to reach certain sub-regional CLLs. For example, the Rhode Island CLL reflects a load reduction equal to 38 percent of the projected load in the Rhode Island load zone in 2015 and 50 percent of the projected load in 2020. This means that some reliability violations will occur even if demand were just under two-thirds of the projected level in 2015 and half of the projected level in 2020. Thus, a demand-only NTA would have to reduce Rhode Island load by one-third to one-half of projected levels.

Exhibit 4-2
CLL for Sub-Regions in Southern New England – 2015 and 2020

Area of Concern	Year	# of Pre-IRP Thermal Violations[1]	Load Reduction Zones	Load in Zones Before Reduction (MW)	Load Reduction (MW)	Percent Load Reduced	Critical Load Level (MW)
Rhode Island	2015	34	RI	2,085	800	38%	1,285
	2020	137	RI	2,206	1,100	50%	1,106
Western NE	2015	6	WMA and CT	9,375	300	3%	9,075
	2020	80	WMA and CT	9,795	1,300	13%	8,495
Connecticut (East to West Transfers)	2015	0[2]	CT	8,224	0	0%	8,224
	2020	10	CT	8,582	1,100	13%	7,482
Connecticut (West to East Transfers)	2015	42[3]	Eastern MA	11,570	800	7%	10,770
	2020	2,269[3]	Eastern MA	12,218	2,400	20%	9,818
Eastern NE	2015	166	Eastern MA	11,570	2,300	20%	9,270
	2020	5,822	Eastern MA	12,218	2,900	24%	9,318

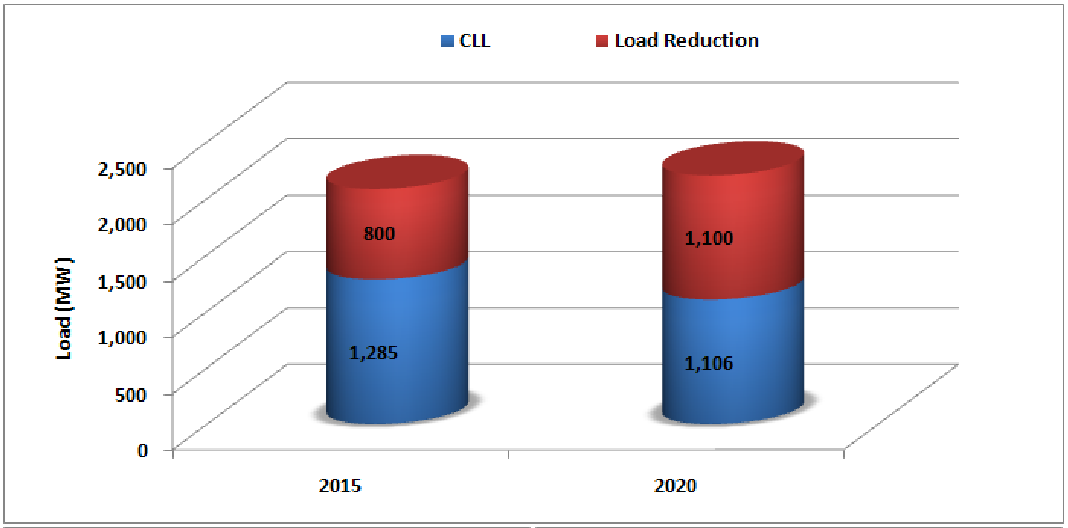
[1] Thermal violation could occur on a single monitored element for multiple contingencies, and a single contingency could cause violations on multiple monitored elements.

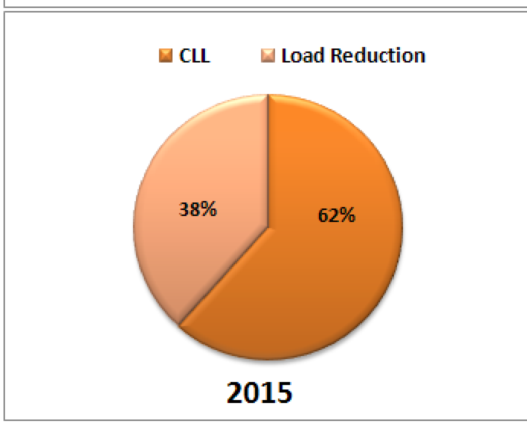
[2] WOOD RIV - NU_1870S_NGR is loaded at 99.8 percent of its emergency rating.

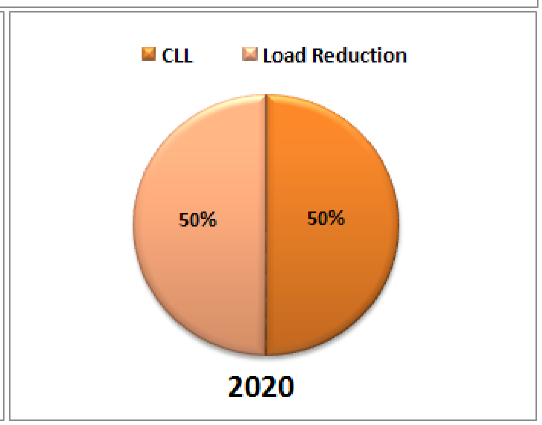
[3] Only those overloaded elements are considered that are within CT.

Exhibit 4-3 shows the results of the CLL analysis for Rhode Island in graphic form. In 2015 a load reduction of 800 MW, which represents 38 percent of the 2,085 MW, is required to produce a CLL of 1,285 MW (62 percent of the projected load). In 2020 the required load reduction increases to 1,100 MW, approximately 50 percent of the total load of 2,206 MW. It results in a CLL of 1,106 MW, or half of the projected load.

Exhibit 4-3
Rhode Island Load Reduction and CLL – 2015 and 2020

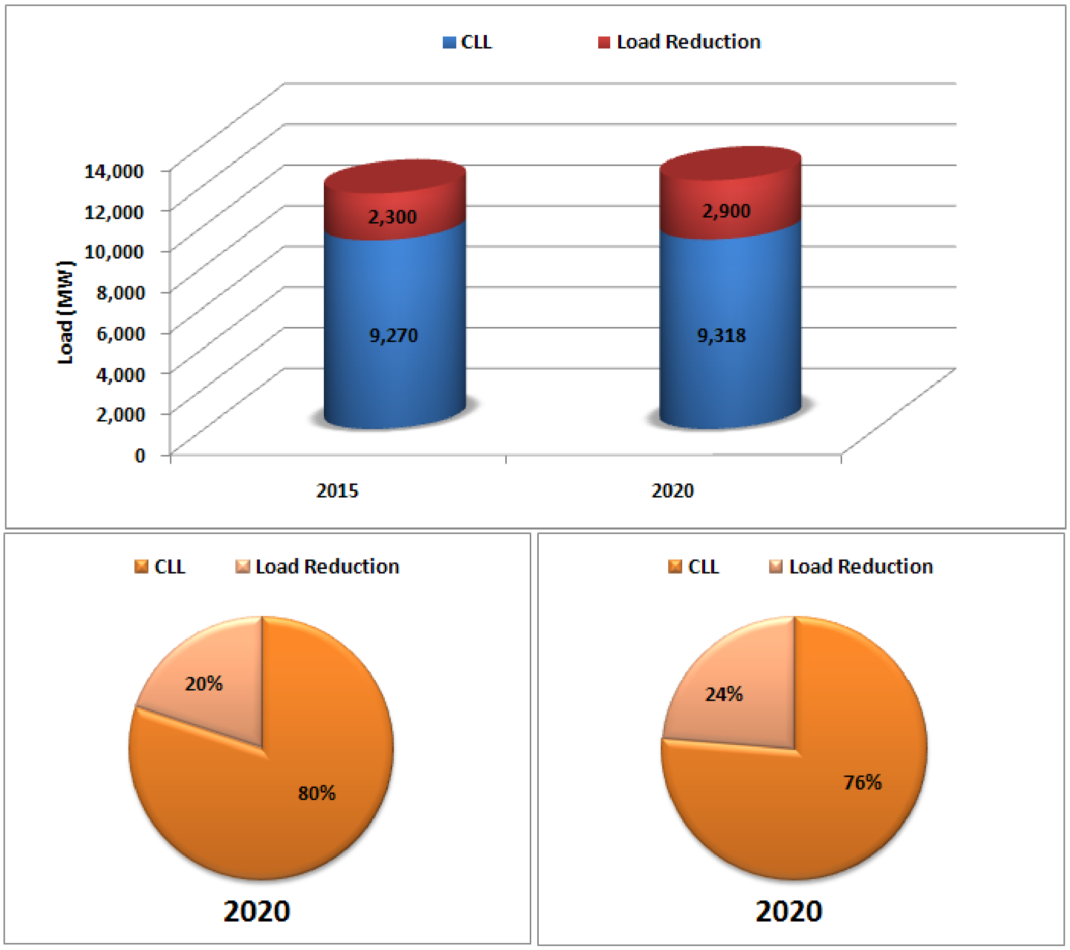






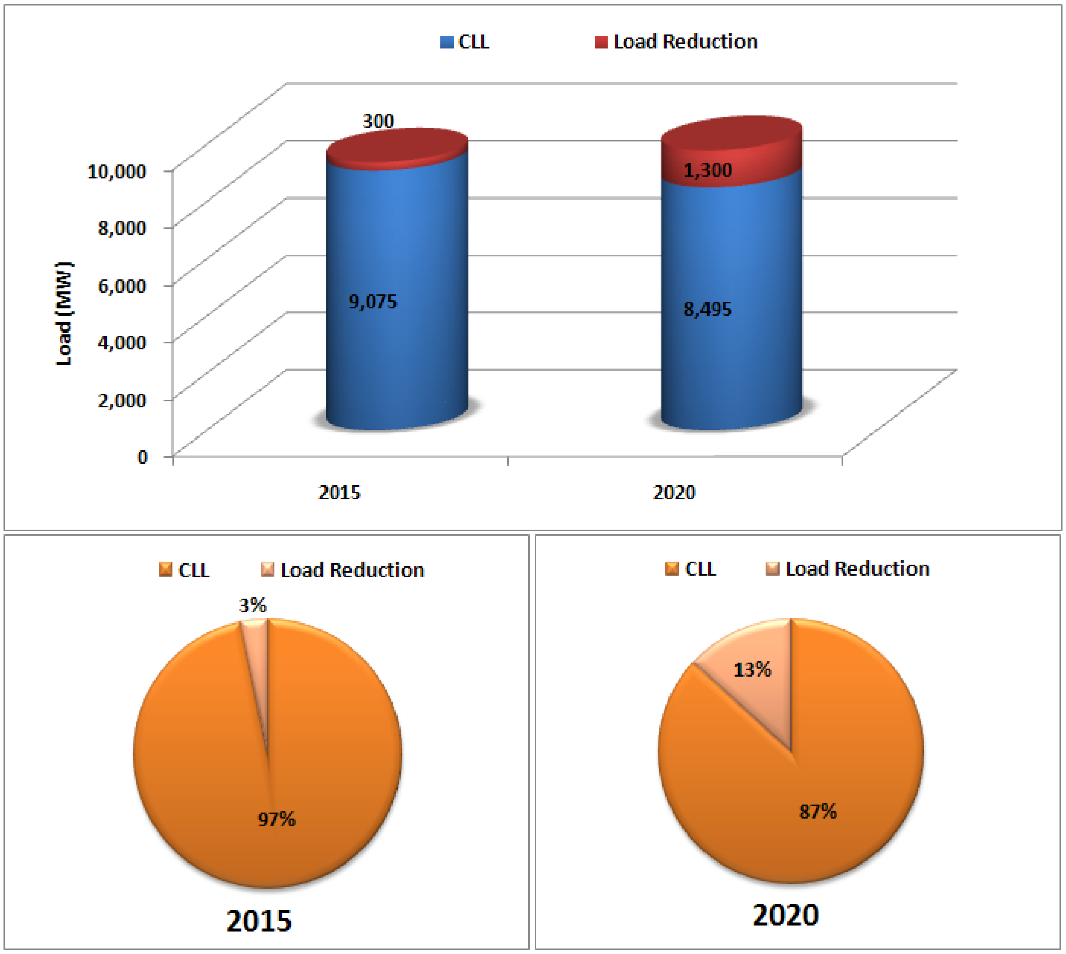
The results of the Eastern NE CLL analysis are shown in Exhibit 4-4. The CLL is 9,270 MW in 2015 and 9,318 MW in 2020. These represent 80 percent of the projected load of 11,570 MW in 2015 and 76 percent of the projected load of 12,218 MW in 2020. The required load reductions are 20 percent in 2015 and 24 percent in 2020.

Exhibit 4-4
Eastern NE Load Reduction and CLL – 2015 and 2020



In Western NE load reductions of 300 MW or 3 percent of projected load in 2015 and 1,300 MW or 13 percent of projected load in 2020 produce CLLs of 9,075 MW (97 percent of load) and 8,495 MW (87 percent of load) in 2015 and 2020, respectively. (See Exhibit 4-5).

Exhibit 4-5
Western NE Load Reduction and CLL – 2015 and 2020



The results of the CLL analysis focused on Connecticut are shown in Exhibits 4-6 and 4-7. Exhibit 4-6 shows that when Connecticut is operating as an importing zone, violations are not observed at the 2015 load level. However, in 2020 violations appear at a Connecticut load level above 7,482 MW, which is 87 percent of the 2020 load level in Connecticut. Exhibit 4-7 shows that in 2015, when Connecticut is operating as an exporting zone, violations appear in Connecticut when the Eastern NE load level is above 10,770 MW, or 93 percent of the 2015 Eastern NE load level. In 2020 violations appear in Connecticut when the Eastern NE load level is above 9,818, or 80 percent of the 2020 load level.

Exhibit 4-6
CLL Analysis With CT Importing (East to West) – 2015 and 2020

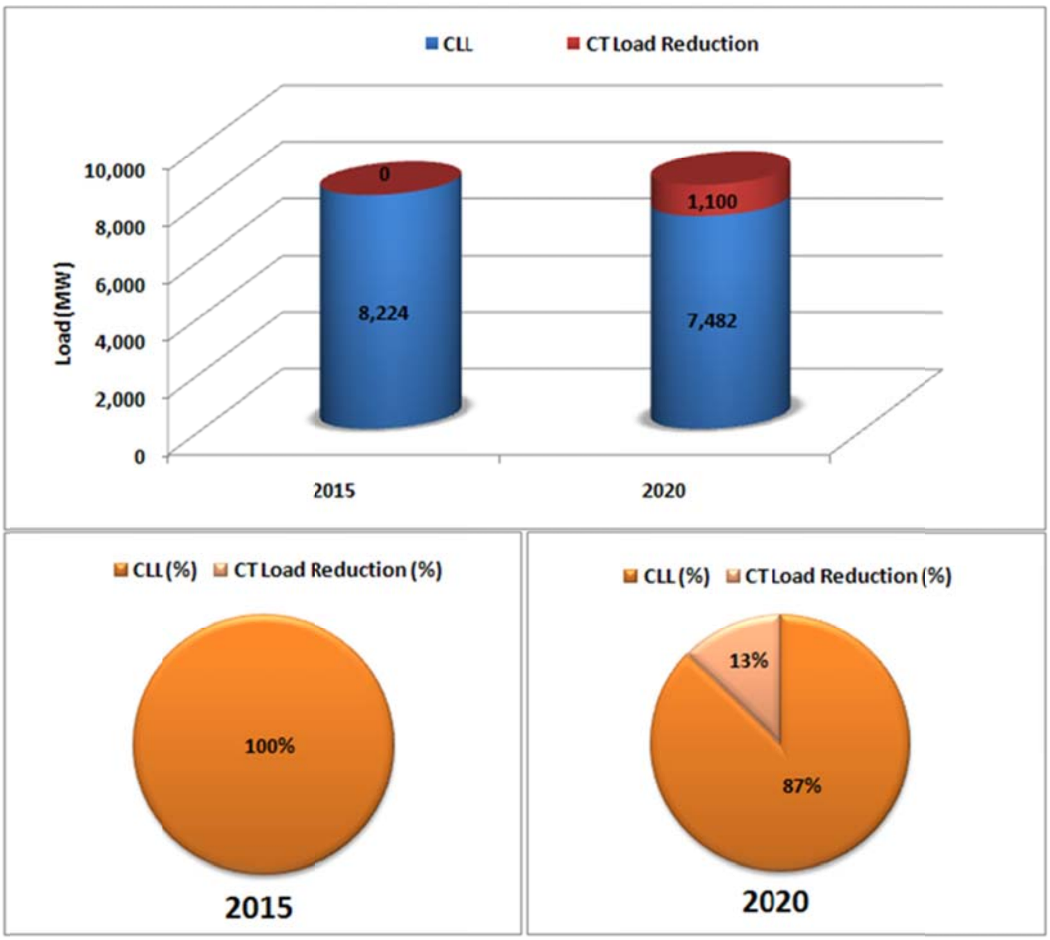
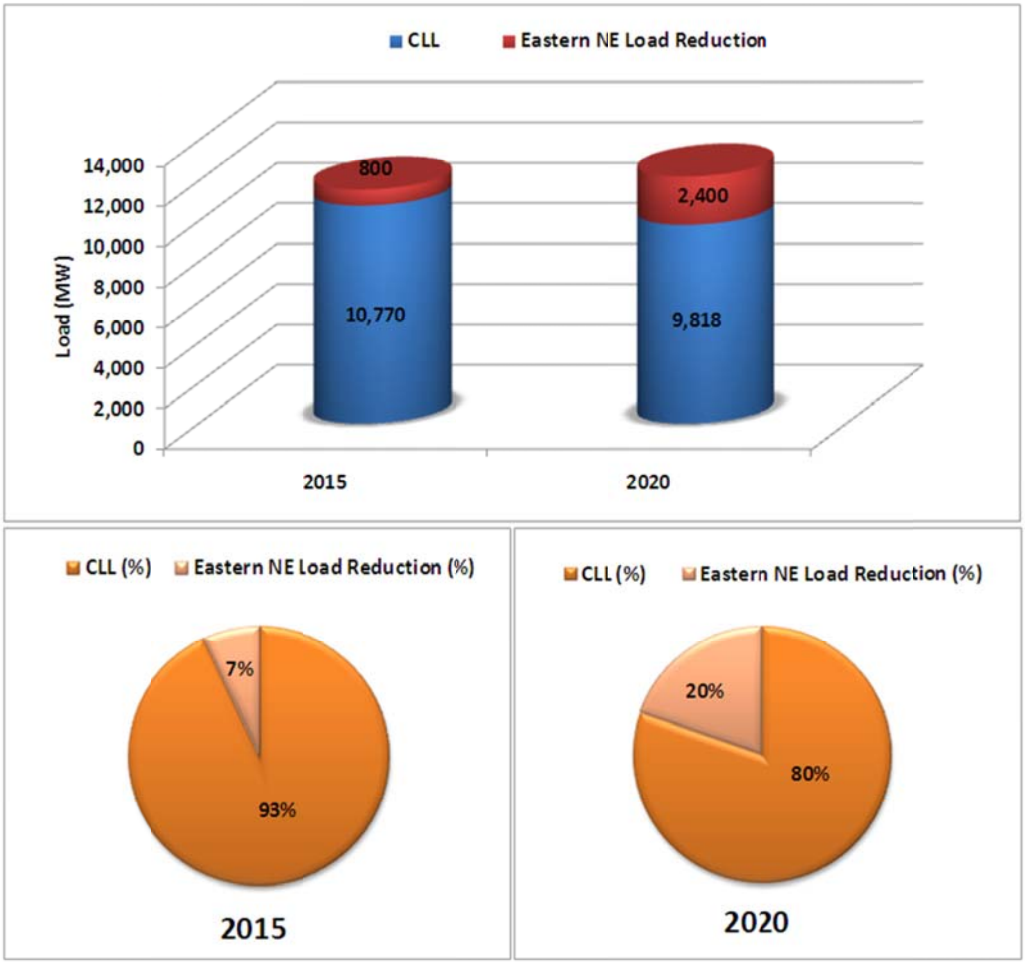


Exhibit 4-7
CLL Analysis With CT Exporting (West to East) – 2015 and 2020



4.3 Conclusion

ICF performed CLL analyses for Eastern NE, Western NE, and Rhode Island to determine the CLL for southern New England. ICF also performed a CLL analysis focused on Connecticut imports and exports. The analyses showed that a reduction of approximately 3,400 MW or 15 percent of the total load in southern New England will be required to resolve all violations in southern New England in 2015. In 2020 the required load reduction increases to 5,300 MW, or 22 percent of the total load of 24,219 MW projected for southern New England.

The calculated load reductions were incremental to the levels of active and passive demand resources already included in the ISO-NE power flow cases. ISO-NE modeled demand resources from FCA #4, which reflected resources expected to be available in the 2013/2014 commitment period.

CHAPTER 5
Assessment of Demand-side Alternatives

5.1 Identification of Demand Resource Alternatives

This chapter describes the approach ICF used to estimate the amount of passive demand resources that could reasonably be expected in southern New England by 2015 and 2020 in excess of that identified in FCA #4. It also compares the expected level of demand resources, including active and passive resources, with the amount required to resolve all violations and produce a demand-only NTA solution.

In the base power flow cases, ISO-NE modeled both active and passive demand resources at the levels of the most recent Forward Capacity Auction, which, at the start of the updated Interstate Needs Assessment, was FCA #4. FCA #4 was held in August 2010 and it procured resources required to satisfy the New England power market's Installed Capacity Requirements (ICR) for the 2013/2014 commitment period. To determine the incremental demand resources required to develop a feasible NTA solution, ICF estimated the additional load reduction required to relieve thermal overloads. ICF further estimated the amount of passive demand resources that could reasonably be expected in the southern New England power market in 2015 and 2020 assuming that growth in resources going forward is similar to that achieved under current funding levels or is aligned with the goals of current regulatory or legislative programs designed to support additional growth in resources. This estimate was compared to the required load reduction. In situations where incremental load reductions beyond that provided by the potential passive demand resources were required, ICF estimated the level of incremental active demand resources necessary to provide the remaining load reductions and assessed the reasonableness of obtaining this amount of resource.

Passive resources typically result from utility-sponsored programs, code or standard changes, and naturally occurring efficiency.[34,35] Within New England, the utility sponsored programs reflect the majority of passive resources that are not already included in the baseline load forecasts. These programs are subject to regulatory approvals at the state level, and are also authorized through state level funding to support utility implementation of programs for consumers.[36] These programs are not considered responsive to real-time market conditions, but are rather influenced by total costs and benefits over the program life. A simple example of this type of passive program is a rebate program for customers who replace refrigerators aged 20 years or older with a new, and more efficient model. The replacement will operate continuously, as the original equipment had, but it will consume less energy when operating, hence providing automatic (passive) savings throughout the day. In contrast, an active program will generally respond to a signal to reduce energy consumption. Like the utility sponsored programs, active programs are not directly integrated into the baseline load projections and reflect additional savings potential to the baseline levels.

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[34] *Naturally occurring potential is the amount of savings estimated to occur as a result of normal market forces, that is, in the absence of any utility or governmental intervention.*

[35] *Load reductions due to code or standard changes and due to naturally occurring efficiency levels are typically included in baseline load forecasts while program levels are estimated separately.*

[36] *Sources for state funding vary from state to state. Surcharges on utility customer bills provide the majority of funding for energy efficiency programs. Other funding sources include revenues from the Regional Greenhouse Gas Program, revenues from the FCM for utility programs, and funds from the American Recovery and Reinvestment Act.*

Although demand resources may provide load and energy savings throughout the course of a day, for purposes of the analysis, ICF focused on the peak load reduction because the ISO-NE Needs Assessment study analyzed system performance under peak load conditions. The power flow cases used for the Needs Assessment represented summer peak load periods in 2015 and 2020. This approach is reasonable because the system is most stressed during peak load conditions.[37]

5.1.1 Estimating Achievable Passive Demand Resources

The projections of passive resource levels were based on the demand reduction targets and state level funding support for energy efficiency and distributed generation for Connecticut, Rhode Island and Massachusetts. ICF estimated and tested two different levels of demand resources in these states:

- **Reference Passive Demand Resource (Reference DR Case)**: This refers to ICF's estimates of passive demand resources that could be achieved for each state if targeted goals for current programs and for expected legislation are achieved at similar levels each year through 2020.
- **Aggressive Passive Demand Resource (Aggressive DR Case)**: This is a more aggressive level of demand resources examined as a sensitivity scenario. This sensitivity considers the potential for passive resources assuming higher, yet reasonably achievable growth in resources occur. It assumes the amount of demand resources that will be available in southern New England will exceed the Reference levels by17 percent in 2020.

Since the analyses presented here-in were completed, ISO-NE has presented initial results of their effort to include projections of energy efficiency in forward analyses for periods beyond the current FCM horizon. The results were presented at the PAC meeting held on November 16, 2011 (see "ISO-NE Proof of Concept Forecast of New State-Sponsored Energy Efficiency"). The draft results presented by ISO span the calendar years 2014 to 2020. Just before finalizing this report, ICF had the opportunity to conduct a preliminary review of the ISO-NE presentation and to compare their draft results of that analysis to those used by ICF. ICF found that the quantities presented by ISO-NE were generally consistent with the assumed passive Demand Resources in the ICF Reference Case analyses for the southern New England load zones through 2020. Please note that ICF additionally modeled an Aggressive Case which included even greater quantities of passive Demand Resources in southern New England.

5.1.1.1 Estimating Achievable Passive Demand Resources in Connecticut

The sources considered for passive demand resources include energy efficiency and small (distributed) renewable generation. For the latter, state level net metering programs for distributed renewables were considered as were programs providing direct funding or subsidies to small renewables.

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[37] System planners also study system operations under conditions other than the peak load. Such studies provide additional insights that can be essential in planning. For example, the voltage profile and dynamic response of the system can change significantly from that of the peak operating period when system is lightly loaded.

Energy Efficiency

ICF's estimate of growth in energy efficiency resources in Connecticut is largely based on projections in the Electric Distribution Companies' Proposed Connecticut Integrated Resource Plan (Connecticut IRP).[38] Specifically, ICF assumed that the energy efficiency available in the Reference DR Case is the energy efficiency achieved through the Reference Level DSM strategy contained in the Connecticut IRP, while the energy efficiency available in the Aggressive DR Cases is characterized by the Targeted DSM Expansion resource strategy contained in the Connecticut IRP. As described in the Connecticut IRP, the Reference Level of energy efficiency reflects the level achieved assuming the continuation of the program structures and designs currently deployed in Connecticut within state approved program budgets.[39] The Targeted passive DSM Expansion resource strategy provides additional DSM savings through four high potential initiatives in Connecticut.[40] The projected incremental peak load reduction for each of the programs from 2015 through 2020 is shown in Exhibit 5-1.

Exhibit 5-1
Incremental Achievable Energy Efficiency in Connecticut – 2015 through 2020

DSM Strategy	Year					
	2015	2016	2017	2018	2019	2020
Reference Level DSM – Incremental (MW)	37.9	37.2	35.7	35.1	34.5	33.9
Targeted DSM Expansion – Incremental (MW)	18.4	18.9	18.4	17.8	19.9	19.2
Aggressive Level DSM – Incremental (MW)	56.3	56.1	54.1	52.9	54.4	53.1

NOTE: Values shown at end-use level.

Source: Response to Interrogatory Q-ENE-001, Connecticut Department of Public Utility Control (DPUC) Docket No. 10-02-07, DPUC Review of the 2010 Integrated Resource Plan.

Distributed Generation

Within Connecticut, ICF identified two types of state sponsored programs that were anticipated to encourage continued additions of passive (non-dispatchable renewable) distributed generation resources. The first, net-metering, allows for facilities installed at specific sites to sell back excess generation to the utility to which it is interconnected. The second consists of direct state sponsored funding mechanisms which promote clean on-site generation resources.

Connecticut has maintained a long-standing net metering program which has helped to support the deployment of distributed resources in the state. In 2006, the number of net metering customers in Connecticut totaled 181. By 2009 this number had grown to 1,348 customers, almost doubling the number of customers in each year.[41] To date in 2011, the total net metering

[38] Proposed Integrated Resource Plan for Connecticut, Prepared by The Brattle Group, The Connecticut Light and Power Company, and United Illuminating Company, January 1, 2010.

[39] Proposed Integrated Resource Plan for Connecticut, Prepared by The Brattle Group, The Connecticut Light and Power Company, and United Illuminating Company, January 1, 2010, Section 2C.

[40] The initiatives are residential new construction "zero energy homes," residential cooling, various commercial and industrial (C&I) applications, and C&I chiller retirement. Integrated Resource Plan for Connecticut, Prepared by The Brattle Group, January 1, 2010, Section 2D.

[41] EIA-861 annual reports 2007 through 2010.

customers reported through March 2011 were 2,254, accounting for 33.7 MW of installed net metering capacity.[42] Historically, to the extent that these resources are not participating in the FCM directly, the impact of the net metering resources on peak and energy related to net metering installations would have been captured in the ISO-NE baseline load forecasts already.

Connecticut's On-Site Renewable Distributed Generation (OSDG) Program has provided grants to support the installation of systems that generate electricity at commercial, industrial and institutional buildings. Systems utilizing solar photovoltaics (PV), wind, fuel cells, landfill gas, low-emission advanced biomass-conversion technologies, run-of-the-river hydropower, wave or tidal power, or ocean-thermal power have been eligible. In the past, most program support has targeted PV and fuel cell projects. This program is supported by the Connecticut Clean Energy Fund (CCEF). The program was initially established in 2005 and the total funding allocated for all selected projects under the OSDG Program through fiscal year 2010 was $66.24 million. Through 2010, funding was granted to support aggregate installed capacity of 20 MW at over 200 sites.

Following the closing of the OSDG Program at the end of fiscal year 2010, CCEF relaunched the program on November 1, 2010, implementing revisions to the application process to allow for more effective management of the program under a tighter budget. The program is now competitive, using an RFP process to select among applicants. The total funding allocated for projects under the OSDG Program through June 30, 2012, is $12.86, $7.2 million (56%) of which is reserved for solar PV projects.

To account for potential passive distributed generation additions under these two programs, or other funding mechanisms, ICF has assumed that by year end 2012, an incremental 20 MW (10 MW per year) of passive distributed generation capacity will be available. Going forward, ICF assumed that there would be continuing support for renewable distributed generation to produce the same average annual growth of 10 MW per year in the Reference DR Case. The Aggressive DR Case assumed this level would increase by 50 percent to an average increment of 15 MW per year.

[42] *EIA-826 report.*

Total Passive Demand Resource Potential

The ISO-NE Needs Assessment assumed that 424 MW of passive demand resource at the end use level would be available in Connecticut according to the FCA #4 results. Starting with this initial passive demand resource level in 2014, the estimates of the passive demand resources in the Reference DR Case and the Aggressive DR Case can be calculated by adding the incremental energy efficiency and distributed generation levels assumed for each year. Exhibit 5-2 presents the total passive demand resources assumed for the Reference DR Case while Exhibit 5-3 presents the same information for the Aggressive DR Case.

Exhibit 5-2
Reference Demand Resource Case Passive Demand Resources in Connecticut

Year	Passive Demand Resource Assumption (MW) [a]	Energy Efficiency Summer Peak (MW)		Passive DG (MW)	
		Total [b]	Annual / Incremental [c]	Total Summer Peak [d, e]	Annual / Incremental [f]
2011	-	-	-	-	5
2012	-	-	-	-	10
2013	424	-	-	-	10
2014		378	-	54	10
2015	472	416	38	57	10
2016	512	453	37	59	10
2017	550	489	36	61	10
2018	588	524	35	64	10
2019	624	558	35	66	10
2020	661	592	34	68	10

(a) Passive demand resources include energy efficiency and derated passive DG. DG is derated to account for the contribution of the resource in MW at the time of summer peak. Values for 2014 are assumed to be consistent with FCA #4 levels modeled by ISO-NE in the Needs Assessment, which can be found in the "New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment Southern New England Regional Working Group (ISO New England, National Grid, Northeast Utilities, and NSTAR)", ISO New England Inc., April 2011, Table 3-1, page 20.

(b) FCA #4 energy efficiency resources assumed in 2014 are estimated through a line item review of resources cleared in FCA #4.

(c) The energy efficiency resources are assumed to be consistent with the Connecticut 2010 IRP. Source: Response of CL&P,UI, and Brattle Group to Interrogatory Q-ENE-001, Connecticut Department of Public Utility Control (DPUC) Docket No. 10-02-07, DPUC Review of the 2010 Integrated Resource Plan.

(d) Total passive DG resources shown reflect the capacity assumed to be available at summer peak. Since passive DG resources are assumed to comprise non-dispatchable renewable resources, the derate is consistent with the expected availability of the renewable resource at the time of the peak condition. For simplicity, ICF has assumed that the renewable resources will comprise a mix of 75 percent solar and 25 percent wind. The solar is assumed to contribute 28 percent of its installed capability at peak based on actual determinations for solar resources through FCA #5. The wind is assumed to contribute 10 percent of its installed capacity at the time of summer peak.

(e) Passive distributed resources assumed available in 2014 are estimated through a line item review of resources cleared in the FCA #4 auction.

(f) Based on the OSDG Program and continued growth in the Connecticut net metering participation, ICF assumes 20 MW incremental installations to be achieved by year end 2012 (assumed 1/2 of the annual increment will be available for the summer peak). Incremental annual growth of 10 MW per year is assumed thereafter.

Exhibit 5-3
Aggressive Demand Resource Case Passive Demand Resources in Connecticut

Year	Passive Demand Resource Assumption (MW) [a]	Energy Efficiency Summer Peak (MW)		Passive DG (MW)	
		Total [b]	Annual / Incremental [c]	Total Summer Peak [d, e]	Annual / Incremental [f]
2011	-	-	-	-	5
2012	-	-	-	-	15
2013	424	-	-	-	15
2014		378	-	57	15
2015	494	434	56	60	15
2016	554	490	56	64	15
2017	612	544	54	67	15
2018	668	597	53	71	15
2019	726	652	54	75	15
2020	783	705	53	78	15

(a) Passive demand resources include energy efficiency and derated passive DG. DG is derated to account for the contribution of the resource in MW at the time of summer peak. Values for 2014 are assumed to be consistent with FCA #4 levels modeled by ISO-NE in the Needs Assessment, which can be found in the "New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment Southern New England Regional Working Group (ISO New England, National Grid, Northeast Utilities, and NSTAR)", ISO New England Inc., April 2011, Table 3-1, page 20.

(b) FCA #4 energy efficiency resources assumed in 2014 are estimated through a line item review of resources cleared in FCA #4.

(c) The energy efficiency resources are assumed to be consistent with the Connecticut 2010 IRP. Source: Response of CL&P,UI, and Brattle Group to Interrogatory Q-ENE-001, Connecticut Department of Public Utility Control (DPUC) Docket No. 10-02-07, DPUC Review of the 2010 Integrated Resource Plan.

(d) Total passive DG resources shown reflect the capacity assumed to be available at summer peak. Since passive DG resources are assumed to comprise non-dispatchable renewable resources, the derate is consistent with the expected availability of the renewable resource at the time of the peak condition. For simplicity, ICF has assumed that the renewable resources will comprise a mix of 75 percent solar and 25 percent wind. The solar is assumed to contribute 28 percent of its installed capability at peak based on actual determinations for solar resources through FCA #5. The wind is assumed to contribute 10 percent of its installed capacity at the time of summer peak.

(e) Passive distributed resources assumed available in 2014 are estimated through a line item review of resources cleared in the FCA #4 auction.

(f) Based on the OSDG Program and continued growth in the Connecticut net metering participation, ICF assumes 20 MW incremental installations to be achieved by year end 2012 (assumed 1/2 of the annual increment will be available for the summer peak). Incremental annual growth of 15 MW per year is assumed thereafter.

The values shown in Exhibits 5-2 and 5-3 reflect the end use level. As the power flow modeling is conducted at the distribution load bus level, the passive demand resources shown above were increased by 5.5 percent to account for distribution system losses.

When compared to the load growth assumed in the load flow cases, the growth in passive resources is quite strong. Between 2015 and 2020, load is anticipated to grow at an annual average growth rate of 0.9 percent. In contrast, in the Reference DR Case, passive demand resources grow at a rate of 6.9 percent annually and at 9.6 percent annually in the Aggressive DR Case.

5.1.1.2 Estimating Achievable Passive Demand Resources in Rhode Island

As with Connecticut, ICF estimated potential passive demand resources for Rhode Island under a Reference DR Case and an Aggressive DR Case. The sources considered for passive demand resources include energy efficiency and small (distributed) renewable generation. For the latter, state level net metering programs for distributed renewables were considered as were programs providing direct funding or subsidies to small renewables.

Energy Efficiency

ICF's estimate of growth in energy efficiency resources in Rhode Island is largely based on the assumption that program goals would continue into the future at the same level as currently targeted. In November of 2010, a settlement agreement was reached with the state on program goals for energy efficiency for the 2011 year.[43] The total approved summer peak MW for Rhode Island was 19 MW. For the Reference DR Case ICF has assumed that the funding levels necessary to achieve this resource level will continue over the forecast horizon, such that an incremental 19 MW are achieved in each year through 2020. The additions are assumed to be incremental to levels already included in the FCA #4 auction results, as such, a total of approximately 115 MW are added above the cleared FCA #4 levels by 2020.

Energy efficiency additions for the Aggressive DR Case were estimated based on the anticipated savings which could occur using forward looking trends filed within a recent annual report to the General Assembly regarding the energy efficiency program performance.[44] Levels of energy efficiency were assumed to reach 30MW by 2014 in this report. ICF assumed that 30 MW could be attained in 2014 and all years thereafter in the Aggressive DR Case.

Distributed Generation

Rhode Island recently established two programs which seek to encourage additions of small, distributed renewable resources throughout the state. The first, HB 6104 (SB 0723), encourages small, land-based renewable energy distributed generation projects. Provisions of the bill provide for Long Term Contracting (LTC) standards for small projects. Within this bill, the procurement of minimum of 40 MW of small scale distributed generation projects is targeted through 2014. There is no enforcement of these targets and no financial penalty if these targets are not met; consequently, they are not considered to be enforceable targets, but rather goals. Further, the 40 MW is considered a subset of LTC procurement targets of a minimum 90 MW in total. Reasoning presented for proposal cited in "The Small Business Renewable Energy Task Force FINDINGS and RECOMMENDATIONS", May 2011, include:

- o The fact that few small renewable energy projects have been developed in Rhode Island, especially when compared to neighbor states, Massachusetts and Connecticut.
- o The Office of Energy Resources had difficulty finding viable projects to fund with the American Recovery and Reinvestment (ARRA) money that was granted to the state.

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[43] Energy Efficiency Program Plan For 2011 Settlement Of The Parties, November 1, 2010, Table E-6 2011 Program Year Goals. The Narragansett Electric Company d/b/a National Grid Docket No. 4209 Attachment 5 Page 7 of 10.

[44] Rhode Island Energy Efficiency And Resource Management Council Annual Report to the General Assembly Required Under RIGL 42- 140.1-5: April 2011. Table 6 Page 14.

- Developers based in Rhode Island are building most of their projects out of state, but would like to do more business here.
- Developers have cited barriers to development including a lack of long term contract options for small projects.
- The current long term contracting standard is burdensome for small projects and there is an RFP only once a year. Developers of smaller projects need a stream-lined and more flexible process.

The targets included in the bill are for 5 MW through year end 2011, 15 MW incremental through year end 2012, and 10 MW incrementally for each of 2013 and 2014 years. ICF has assumed that these targets will be met (despite lack of enforcement mechanism). To estimate summer resources, year-end targets for prior year are assumed to be summer available capacity in the current year plus half of the current year target. Incremental annual targets equal to the last year goal are included for all years going forward. The Reference DR Case and Aggressive DR Case relied on these same assumptions, given the already aggressive nature of the Reference Case assumption.

The second program is net metering. As in Connecticut, net metering has been a long-time offered program. In August 1998, the Rhode Island Public Utilities Commission (RIPUC) issued an order (Docket 2710) requiring Narragansett Electric (a subsidiary of National Grid), serving 99 percent of the state's mainland customers, to offer net metering to all customers generating electricity using renewable-energy systems with a maximum capacity of 25 kW. In 2006, Rhode Island enacted legislation that allows the RIPUC to establish standards for net metering. Legislation enacted in July 2007 (H.B. 5566) and July 2008 (H.B. 7809) significantly expanded the availability and appeal of net metering in Rhode Island. Legislation passed in July 2009 (SB 485) further improved net metering in Rhode Island by offering the choice of monthly compensation or roll-over for regular customers during a 12-month period and meter aggregation (up to 10 meters) for select groups. The legislation limited net metering to 2 percent of a load serving entity's peak load.

Currently, there is proposed legislation to modify the net metering laws yet again. Bills 2011-S 0457 A and 2011-H 5939 A (Senate and House versions with similar objectives) proposed the following:

- Net-metering would be limited (in accordance with federal requirements) to those projects connected to meters and where the use of the power is located in the same complex as the energy production site.
- There are restrictions on ownership, and all of the net metered accounts at the eligible net metering system site must be the accounts of the same customer of record and customers are not permitted to enter into agreements or arrangements to change the name on accounts for the purpose of artificially expanding the eligible net metering system site to contiguous sites in an attempt to avoid this restriction. The exceptions to this are systems owned by or operated on behalf of a municipality or multi-municipal collaborative.
- The maximum allowable capacity for eligible net metering systems, based on nameplate capacity, shall be five megawatts (5 MW).

- The aggregate amount of net metering in Rhode Island shall not exceed three percent (3%) of peak load (up from 2 percent), provided that at least two megawatts (2 MW) are reserved for projects of less than fifty kilowatts (50 kW).
- "Renewable Net Metering Credit" means a credit that applies to an Eligible Net Metering System up to one hundred percent (100%) of the renewable self-generator's usage at the Eligible Net Metering System Site over the applicable billing period.
- If the electricity generated by an eligible net metering system during a billing period is greater than the net metering customer's usage on accounts at the eligible net metering system site during the billing period, the customer shall be paid by excess renewable net metering credits for the excess electricity generated beyond the net metering customer's usage at the eligible net metering system site up to an additional twenty-five percent (25%) of the renewable self-generator's consumption during the billing period; unless the electric distribution company and net metering customer have agreed to a billing plan.

ICF has assumed that the bills will be passed largely as is by the House and Senate, effectively increasing the amount of resources allowed to qualify as net metering in Rhode Island. Going forward, we have assumed that the passive demand resources added as distributed generation associated with the net metering is at 3 percent of the ISO-NE projected 50/50 peak levels from the 2010 CELT report for the Reference Case. Under the Aggressive Case, the 3 percent cap is maintained; however, it is applied to the 90/10 peak load forecast.

Total Passive Demand Resource Potential

The ISO-NE Needs Assessment assumed that 85 MW of passive demand resources at the end use level would be available in Rhode Island according to the FCA #4 results. Starting with this initial passive demand resource level in 2014, the estimates of the passive demand resources in the Reference DR Case and the Aggressive DR Case can be calculated by adding the incremental energy efficiency and distributed generation levels assumed for each year. Exhibit 5-4 presents the total passive demand resource assumed for the Reference Demand Resource Case while Exhibit 5-5 presents the same information for the Aggressive Demand Resource Case for Rhode Island.

Exhibit 5-4
Reference Demand Resource Case Passive Demand Resources in Rhode Island

Year	Passive Demand Resource Assumption (MW) [a]	Energy Efficiency Summer Peak (MW)		Passive DG (MW)	
		Total [b]	Annual / Incremental [c]	Total Summer Peak [d, e]	Annual / Incremental [f]
2011	-	-	-	-	58
2012	-	-	-	-	11
2013	85	-	-	-	13
2014		84	-	-	11
2015	128	103	19	26	11
2016	150	122	19	28	11
2017	172	141	19	31	11
2018	193	160	19	33	11
2019	215	179	19	36	11
2020	237	198	19	38	11

(a) Passive demand resources include energy efficiency and derated passive DG. DG is derated to account for the contribution of the resource in MW at the time of summer peak. Values for 2014 are assumed to be consistent with FCA #4 levels modeled by ISO-NE in the Needs Assessment, which can be found in the "New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment Southern New England Regional Working Group (ISO New England, National Grid, Northeast Utilities, and NSTAR)", ISO New England Inc., April 2011, Table 3-1, page 20.

(b) FCA #4 energy efficiency resources assumed in 2014 are estimated through a line item review of resources cleared in FCA #4.

(c) ENERGY EFFICIENCY PROGRAM PLAN FOR 2011 SETTLEMENT OF THE PARTIES November 1, 2010 Table E-6 2011 Program Year Goals. The Narragansett Electric Company d/b/a National Grid Docket No. 4209 Attachment 5 Page 7 of 10.

(d) Total passive DG resources shown reflect the capacity assumed to be available at summer peak. Since passive DG resources are assumed to comprise non-dispatchable renewable resources, the derate is consistent with the expected availability of the renewable resource at the time of the peak condition. For simplicity, ICF has assumed that the renewable resources will comprise a mix of 75 percent solar and 25 percent wind. The solar is assumed to contribute 28 percent of its installed capability at peak based on actual determinations for solar resources through FCA #5. The wind is assumed to contribute 10 percent of its installed capacity at the time of summer peak.

(e) Passive distributed resources assumed available in 2014 are estimated through a line item review of resources cleared in the FCA #4 auction.

(f) Based on the sum of 1) targets of 40MW by 2014 under long-term procurement goals and assuming 10MW per year thereafter; and 2) total net metering additions assumed equal to 3 percent of the annual projected peak for Rhode Island in ISO-NE 50/50 forecast as published in the 2010 CELT.

Exhibit 5-5
Aggressive Demand Resource Case Passive Demand Resources in Rhode Island

Year	Passive Demand Resource Assumption (MW) [a]	Energy Efficiency Summer Peak (MW)		Passive DG (MW)	
		Total [b]	Annual / Incremental [c]	Total Summer Peak [d, e]	Annual / Incremental [f]
2011	-	-	-	-	64
2012	-	-	-	-	12
2013	85	-	-	-	13
2014		84	-	-	11
2015	141	114	30	27	10
2016	174	144	30	30	11
2017	207	175	30	32	11
2018	240	205	30	35	11
2019	273	236	30	38	10
2020	306	266	30	40	11

(a) Passive demand resources include energy efficiency and derated passive DG. DG is derated to account for the contribution of the resource in MW at the time of summer peak. Values for 2014 are assumed to be consistent with FCA #4 levels modeled by ISO-NE in the Needs Assessment, which can be found in the "New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment Southern New England Regional Working Group (ISO New England, National Grid, Northeast Utilities, and NSTAR)", ISO New England Inc., April 2011, Table 3-1, page 20.

(b) FCA #4 energy efficiency resources assumed in 2014 are estimated through a line item review of resources cleared in FCA #4.

(c) RHODE ISLAND ENERGY EFFICIENCY AND RESOURCE MANAGEMENT COUNCIL Annual Report to the General Assembly | Required Under RIGL 42- 140.1-5: April 2011. Table 6 Page 14.

(d) Total passive DG resources shown reflect the capacity assumed to be available at summer peak. Since passive DG resources are assumed to comprise non-dispatchable renewable resources, the derate is consistent with the expected availability of the renewable resource at the time of the peak condition. For simplicity, ICF has assumed that the renewable resources will comprise a mix of 75 percent solar and 25 percent wind. The solar is assumed to contribute 28 percent of its installed capability at peak based on actual determinations for solar resources through FCA #5. The wind is assumed to contribute 10 percent of its installed capacity at the time of summer peak.

(e) Passive distributed resources assumed available in 2014 are estimated through a line item review of resources cleared in the FCA #4 auction.

(f) Based on the sum of 1) targets of 40MW by 2014 under long-term procurement goals and assuming 10MW per year thereafter; and 2) total net metering additions assumed equal to 3 percent of the annual projected peak for Rhode Island in ISO-NE 90/10 forecast as published in the 2010 CELT.

The values shown in Exhibits 5-4 and 5-5 reflect the end use level. Because the power flow modeling is conducted at the distribution load bus level, the passive DR resources shown above were increased by 5.5 percent to account for distribution system losses.

When compared to the load growth assumed in the load flow cases, the growth in passive resources is quite strong. Between 2015 and 2020, load is anticipated to grow at an annual average growth rate of 1.0 percent. In contrast, in the Reference DR Case, passive demand resources grow at a rate of 13 percent annually and at 17 percent annually in the Aggressive DR Case.

5.1.1.3 Estimating Achievable Passive Demand Resources in Massachusetts

As with Rhode Island and Connecticut, ICF developed Reference DR Case and Aggressive DR Case estimates of passive demand resources for Massachusetts. These projections were based on targets for energy efficiency programs, analysis of net metering legislation, and the potential for additional funding for distributed generation that does not qualify for net metering.

Energy Efficiency

In Massachusetts, targets for energy efficiency are established within a three year program. The current program spans the period 2010, 2011, and 2012. The program targets for the current year (2011) are 145 MW for the state while the targets for 2012 increase to 179 MW.[45] Funding for these program targets has been set aside; however targets for future years are not yet established. To reflect the potential for energy efficiency additions in Massachusetts under the Reference DR Case conditions, ICF assumed that the 2011 levels of 145 MW would be targeted in all years through 2020, while in the Aggressive DR Case, a target equal to the 2012 goals of 179 MW was assumed. To achieve these levels, it is assumed that the per MW cost of installation is increasing based on programs costs filed in the current Massachusetts three year plan, such that total funding per year is increasing although the targets remain constant.

Distributed Generation

Net metering legislation in Massachusetts has existed since the early 1980s, however, it was not until legislation in 2009 that activity promoting the addition of passive distributed generation on a significant scale was achieved. The Massachusetts Department of Energy Resources (DOER) reports that 14 MW of renewable distributed generation were installed in Massachusetts in 2009. This increased to 21 MW in 2010. Projected additions in 2011 will be 45 MW, based on installations through May 2011.The current net metering legislation restricts net metering to 1 percent of the peak load. Based on the current number of applications for net metering and the trend reflected in the 2010/2011 additions, this limit (implying roughly 160 MW), would be reached within 2 to 3 years. Given these trends, ICF has assumed that, as in Rhode Island, the 1 percent limit will be modified in the future to continue to promote and encourage additions of small scale renewables. Further, we acknowledge that additional funding outside of net metering may contribute to additions. ICF has assumed the Reference DR Case will average an addition of 14 MW per year, consistent with levels in 2009, while the Aggressive DR Case will average 45 MW per year, consistent with projected additions in 2011.

[45] *2010 – 2012 Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan, October 29, 2009, pages 98-101.*

Total Passive Demand Resource Potential

The ISO-NE Needs Assessment assumed that 533 MW of passive demand resources at the end use level would be available in Massachusetts according to the FCA #4 results. Starting with this initial passive demand resource level in 2014, the estimates of the passive demand resources in the Reference DR Case and the Aggressive DR Case can be calculated by adding the incremental energy efficiency and distributed generation levels assumed for each year. Exhibit 5-6 presents the total passive demand resources assumed for the Reference DR Case while Exhibit 5-7 presents the same information for the Aggressive DR Case.

Exhibit 5-6
Reference DR Case Passive Demand Resources in Massachusetts

Year	Passive Demand Resource Assumption (MW) [a]	Energy Efficiency Summer Peak (MW)		Passive DG (MW)	
		Total [b]	Annual / Incremental [c]	Total Summer Peak [d, e]	Annual / Incremental [f]
2011	-	-	-	-	14
2012	-	-	-	-	14
2013	553	-	-	-	14
2014		521	-	62	14
2015	770	666	145	103	14
2016	918	811	145	107	14
2017	1,067	956	145	111	14
2018	1,216	1,101	145	114	14
2019	1,364	1,246	145	118	14
2020	1,513	1,391	145	122	14

(a) Passive demand resources include energy efficiency and derated passive DG. DG is derated to account for the contribution of the resource in MW at the time of summer peak. Values for 2014 are assumed to be consistent with FCA #4 levels modeled by ISO-NE in the Needs Assessment, which can be found in the "New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment Southern New England Regional Working Group (ISO New England, National Grid, Northeast Utilities, and NSTAR)", ISO New England Inc., April 2011, Table 3-1, page 20.

(b) FCA #4 energy efficiency resources assumed in 2014 are estimated through a line item review of resources cleared in FCA #4.

(c) 2010 - 2012 Approved Massachusetts Energy Efficiency Targets as stated in "2010 – 2012 Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan", October 29, 2009, pages 98-101. Assumed to equal the 2011 targets in all years following the FCA#4.

(d) Total passive DG resources shown reflect the capacity assumed to be available at summer peak. Since passive DG resources are assumed to comprise non-dispatchable renewable resources, the derate is consistent with the expected availability of the renewable resource at the time of the peak condition. For simplicity, ICF has assumed that the renewable resources will comprise a mix of 75 percent solar and 25 percent wind. The solar is assumed to contribute 28 percent of its installed capability at peak based on actual determinations for solar resources through FCA #5. The wind is assumed to contribute 10 percent of its installed capacity at the time of summer peak.

(e) Passive distributed resources assumed available in 2014 are estimated through a line item review of resources cleared in the FCA #4 auction.

(f) Assumed to equal 14 MW consistent with projected additions in 2009.

Exhibit 5-7
Aggressive DR Case Passive Demand Resources in Massachusetts

Year	Passive Demand Resource Assumption (MW) [a]	Energy Efficiency Summer Peak (MW)		Passive DG (MW)	
		Total [b]	Annual / Incremental [c]	Total Summer Peak [d, e]	Annual / Incremental [f]
2011	-	-	-	-	45
2012	-	-	-	-	45
2013	553	-	-	-	45
2014		521	-	84	45
2015	795	700	179	94	45
2016	984	879	179	105	45
2017	1,174	1,058	179	115	45
2018	1,363	1,237	179	126	45
2019	1,553	1,416	179	137	45
2020	1,742	1,595	179	147	45

(a) Passive demand resources include energy efficiency and derated passive DG. DG is derated to account for the contribution of the resource in MW at the time of summer peak. Values for 2014 are assumed to be consistent with FCA #4 levels modeled by ISO-NE in the Needs Assessment, which can be found in the "New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment Southern New England Regional Working Group (ISO New England, National Grid, Northeast Utilities, and NSTAR)", ISO New England Inc., April 2011, Table 3-1, page 20.

(b) FCA #4 energy efficiency resources assumed in 2014 are estimated through a line item review of resources cleared in FCA #4.

(c) 2010 - 2012 Approved Massachusetts Energy Efficiency Targets as stated in "2010 – 2012 Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan", October 29, 2009, pages 98-101. Assumed to equal the 2012 targets in all years following the FCA#4.

(d) Total passive DG resources shown reflect the capacity assumed to be available at summer peak. Since passive DG resources are assumed to comprise non-dispatchable renewable resources, the derate is consistent with the expected availability of the renewable resource at the time of the peak condition. For simplicity, ICF has assumed that the renewable resources will comprise a mix of 75 percent solar and 25 percent wind. The solar is assumed to contribute 28 percent of its installed capability at peak based on actual determinations for solar resources through FCA #5. The wind is assumed to contribute 10 percent of its installed capacity at the time of summer peak.

(e) Passive distributed resources assumed available in 2014 are estimated through a line item review of resources cleared in the FCA #4 auction.

(f) Assumed to equal 45 MW consistent with projected additions for 2011 based on May year to date additions.

The values shown in Exhibits 5-6 and 5-7 reflect the end use level. Because the power flow modeling is conducted at the distribution load bus level, the passive DR resources shown above were increased by 5.5 percent to account for distribution system losses.

When compared to the load growth assumed in the load flow cases, the growth in passive resources is quite strong. Between 2015 and 2020, load is anticipated to grow at an annual average growth rate of 1.1 percent. In contrast, passive demand resources grow at a rate of 14.5 percent annually in the Reference DR Case, and at 17.0 percent annually in the Aggressive DR Case.

5.1.1.4 Southern New England Passive Demand Resource Potential

The results of the analysis conducted to identify the passive demand side resource peak potential are shown in Exhibit 5-8. The table shows the passive demand resource capacity used in the Reference DR Case and the Aggressive DR Case for each state in 2015 and 2020. In 2015 Rhode Island has an incremental potential achievable passive demand resource of 128 MW at the end use level in the Reference DR Case and 141 MW in the Aggressive DR Case. The Reference DR Case increases by 85 percent through 2020 to a total of 237 MW while the Aggressive DR Case more than doubles to 306 MW. In Massachusetts, the passive demand resources in the Reference DR Case and Aggressive DR Case are at roughly 800 MW in 2015. In 2020 these roughly double in the Reference DR Case, while they increase by nearly 120 percent in the Aggressive DR Case. In Rhode Island and Massachusetts the gains in passive resources in both the Reference DR Case and Aggressive DR Case are very strong, with annual average growth rates between 13 and 17 percent. Connecticut resources also increase significantly in both the Reference DR Case and Aggressive DR Case, though more modestly than in Rhode Island or Massachusetts. Connecticut resources are assumed to increase by roughly 40 percent in the Reference DR Case and 60 percent in the Aggressive DR Case, or at annual average growth rates of 7 percent and 10 percent, respectively.

Exhibit 5-8
Total Potential Passive Demand Resource by State – 2015 and 2020

State	Year	Total Passive DR Applied – End Use Level (MW)		Total Passive DR Applied – Load Bus Level (MW)	
		Reference Case	Aggressive Case	Reference Case	Aggressive Case
Rhode Island	2015	128	141	136	149
	2020	237	306	250	323
Massachusetts	2015	770	795	812	838
	2020	1513	1742	1597	1838
Connecticut	2015	472	494	498	522
	2020	661	783	697	826
Total	2015	1,370	1,430	1,446	1,509
	2020	2,411	2,831	2,543	2,987

NOTE: Values shown at the load bus level include 5.5 percent distribution losses from end use level.

Once the end-use levels were identified, they were adjusted to load bus levels for use in the load flow modeling. To evaluate the potential for the passive demand resources to serve as an NTA, the estimated state totals were allocated to the local load areas. Only loads in the southern New England market area were reduced. Exhibit 5-9 presents the total passive demand resource potential at the load bus level by sub-region for each of the 3 sub-regions analyzed.

Exhibit 5-9
Total Potential Passive Demand Resource by Sub-Region – 2015 and 2020

Area of Concern	Year	Total Passive DR Applied (MW)	
		Reference Case	Aggressive Case
Rhode Island	2015	136	149
	2020	250	323
Western NE [1]	2015	597	623
	2020	891	1,049
Eastern NE	2015	713	736
	2020	1,403	1,615
Total	2015	1,446	1,509
	2020	2,543	2,987

NOTE: Values are shown at the load bus level and include 5.5 percent distribution losses from end use level.

[1] Massachusetts is split between Western and Eastern NE. Roughly 12 percent of Massachusetts falls in Western NE while the remaining falls into Eastern NE.

Because the load flow analysis already assumes values consistent with FCA #4, only incremental levels over and above the FCA #4 levels were included in the analysis. Exhibit 5-10 presents the incremental additions to the load flow analysis at the load bus level by sub-region. This is the same as the total shown in Exhibit 5-9 less the amount already included in the Needs Assessment base power flow cases.

Exhibit 5-10
Incremental Potential Passive Demand Resource by Sub-Region – 2015 and 2020

Area of Concern	Year	Incremental Passive DR Applied (MW)	
		Reference Case	Aggressive Case
Rhode Island	2015	47	61
	2020	161	235
Western NE [1]	2015	86	113
	2020	380	538
Eastern NE	2015	208	231
	2020	897	1,110
Total	2015	342	405
	2020	1,439	1,883

NOTE: Values are shown at the load bus level and include 5.5 percent distribution losses from end use level.

[1] Massachusetts is split between Western and Eastern NE. Roughly 12 percent of Massachusetts falls in Western NE while the remaining falls into Eastern NE.

5.2 Comparison of Results of CLL and DSM Potential Analyses

The CLL analysis provides an estimate of the amount of load reduction that will be required to develop a demand-only NTA solution. However, as it does not provide an indication of the quantity or type of resources available to achieve the load reduction levels, it does not provide an indication of the feasibility or configuration of a demand-only NTA solution. The ability to develop a realistic demand-only solution depends on the amount of available demand resources relative to the load reduction required to achieve the CLL. ICF assessed the feasibility of a demand-only solution by comparing the load reductions implied by the CLL against the estimated amount of demand resources necessary to achieve the equivalent reduction.

The analysis considers two types of demand side resources: passive and active. Passive resources peak contribution reflects the peak MW savings associated with energy efficiency programs and other passive resources such as non-dispatchable distributed generation. Passive energy efficiency programs are generally considered reliable; that is, they are expected to be available at peak in the quantity projected based on the successful installation of the equipment projected within that program. Given the high reliability of energy efficiency measures to perform at peak, these resources can be considered to provide a one MW reduction in load for every one MW of resource provided. In contrast, passive distributed generation resources such as wind and solar resources are intermittent, and produce widely varying levels of energy based on weather and other conditions; the name-plate capacity ratings of such resources must be discounted to account for availability of the resource at peak.

Active demand resources are akin to dispatchable generation resources in the sense that they are called on to perform under certain conditions. As such, active resources are subject to a performance factor associated with the responsiveness and availability of that resource. Because active demand resources do not have the same reliability of performance as energy efficiency programs, the addition of one MW of active resource is not the equivalent of a one MW reduction in load.

The comparison of the load reduction required to achieve the CLL to the potential demand resources required to produce that same load reduction was conducted in two main steps. First, the potential for passive demand resources to continue to penetrate the market at current and projected state funding levels was evaluated. And second, the quantity of additional active demand resources necessary to fill the gap remaining after accounting for the potential passive demand resources was identified and compared to current levels and growth trends.

5.2.1 <u>Comparison of CLL Results to the Estimated Passive Demand Resources</u>

The comparison of achievable passive demand resource to the load reduction required to achieve a CLL showed that the achievable passive demand resource capacity in southern New England is significantly lower than the amount required for a demand-only NTA. The results for all of southern New England are shown in Exhibit 5-11. In 2015 the incremental potential achievable passive demand resource in the Reference DR Case of 342 MW is only 10 percent of the 3,400 MW load reduction required to achieve the CLL. The Aggressive DR Case likewise reflects a small fraction – only 12 percent – of the total requirement. The ratio improves slightly in 2020, but it is still significantly short. The Reference DR Case provides 27 percent of the load reduction required to achieve the CLL, and the Aggressive DR Case provide 35 percent.

These results are striking because, as discussed above, the estimate of the load reduction required for the CLL is conservatively low, and the actual CLL is expected to be higher than the estimated amounts. However, the assumptions used in developing the estimates of the required total demand resource potential produced aggressive estimates. Therefore the comparisons shown provide an optimistic view of the ability to develop a demand-only NTA solution that would resolve all the violations that Interstate addresses.

Exhibit 5-11
Available and Required Demand Resources to Resolve All Violations in Combination NTA

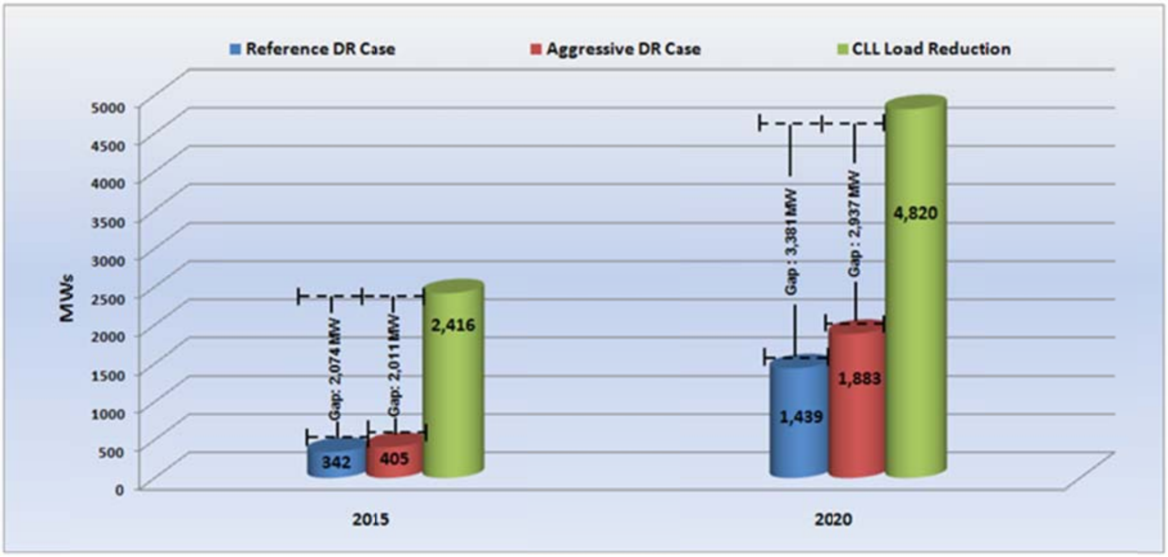
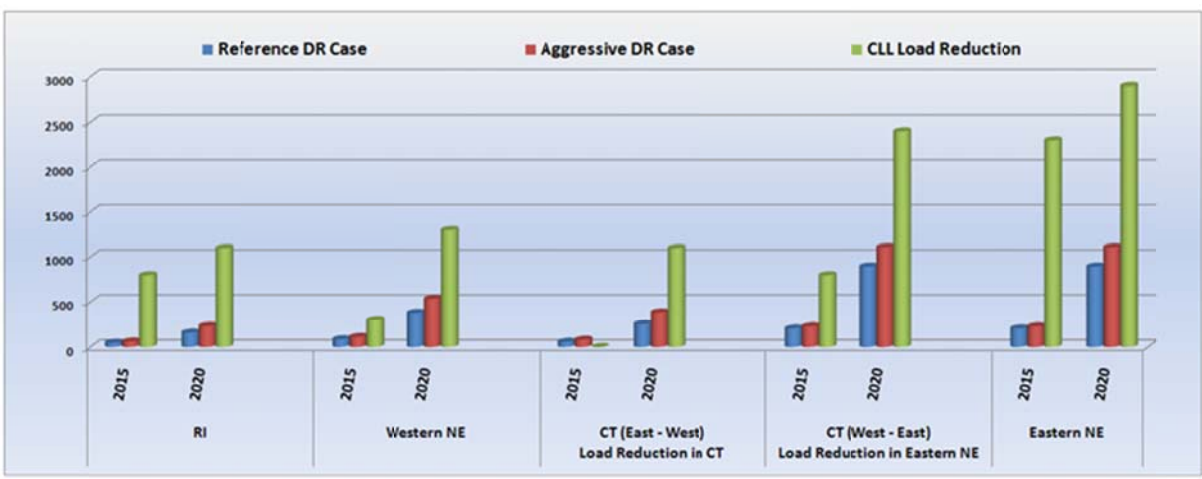


Exhibit 5-12 shows the comparison by sub-region. In almost all cases the potentially achievable demand resource is significantly lower than the required load reduction.

Exhibit 5-12
Available and Required Demand Resources by Sub-Region in Combination NTA



The gaps identified in Exhibit 5-11 in the Reference DR Case are indicative of the load reduction required over and above the passive resources considered to be achievable at current funding levels. ICF considered whether these gaps could be satisfied through addition of incremental active demand resources.

5.2.2 Determination of Active Demand Resource Requirements

It is clear from the foregoing results that the passive peak demand resources (including distributed generation) anticipated to be achievable under the Reference DR Case and the Aggressive DR Case will not be sufficient to produce a demand-only NTA solution equivalent to the load reduction necessary to achieve the CLL in southern New England. Exhibit 5-13 identifies the gap for each sub-region and all of southern New England in the Reference DR Case, and Exhibit 5-14 shows the gap in the Aggressive DR Case. In both cases additional demand reduction equivalent to the identified gap will be required to attain the CLL and eliminate all violations. Potential avenues for additional demand reductions include increased funding levels for passive programs, and active demand response resources. ICF assumed the additional demand reductions would be satisfied with active demand resources.

Exhibit 5-13
Load Reduction Required to Achieve the CLL – Reference DR Case

Sub-Region	2015			2020		
	Total Load Reduction Needed to Reach CLL	Achievable Passive Demand	Gap	Total Load Reduction Needed to Reach CLL	Achievable Passive Demand	Gap
	MW	MW	MW	MW	MW	MW
Rhode Island	800	47	753	1,100	161	939
Western New England	300	86	214	1,300	380	920
Eastern New England	2300	208	2,092	2,900	897	2,003
Southern New England	3,400	342	3,058	5,300	1,439	3,861

NOTE: Values shown at the load bus level.

Exhibit 5-14
Load Reduction Required to Achieve the CLL – Aggressive DR Case

Sub-Region	2015			2020		
	Total Load Reduction Needed to Reach CLL	Achievable Passive Demand	Gap	Total Load Reduction Needed to Reach CLL	Achievable Passive Demand	Gap
	MW	MW	MW	MW	MW	MW
Rhode Island	800	61	739	1,100	235	865
Western New England	300	113	187	1,300	538	762
Eastern New England	2300	231	2,069	2,900	1,110	1,790
Southern New England	3,400	405	2,995	5,300	1,883	3,417

NOTE: Values shown at the load bus level.

Active demand resources do not necessarily provide a one MW load reduction for every one MW cleared. To estimate the additional quantity of active demand resources that would be required to provide load reductions of 3058 MW to 3861 MW that would be required to fill the gap in the Reference DR Case, ICF used the historical performance of active resources to determine an assumed performance rate for such resources. Through FCA #5, ISO-NE used the historical performance rating of the demand response available during the FCM transition period, which reflected an average of several past years of OP4 events and audits to calculate performance rates. The transition period resources do not reflect the resources cleared in the FCM auctions. This approach provides a conservatively low estimate of the active demand resources required to fill the gap, given that it does not consider the increased frequency at which the active demand resources would be called on to perform as the reliance on these resources increases. This increase in frequency could lead to even lower performance, a problem referred to as “fatigue”. To help inform these latter points, an analysis of active demand resource duration analysis was performed. This is discussed in Section 5.3 below.

When considering the ability of active demand resources to fill the gap identified above, between the CLL and the achievable passive demand resource, it is important to factor in the performance of the active demand resource. This is because the level of demand reduction achieved from active demand resources is less than the qualified resource capacity. That is, when called to operate, the actual performance of active demand resources is less than 100 percent. Therefore the capacity of each active demand resource is derated by the performance rate when determining the amount of active demand resources needed to provide the required load reduction. Exhibit 5-15 presents the historical performance of active demand resources as applied in the assumptions for FCA #5 for the areas examined in the CLL analysis. For long-term transmission planning purposes, Real Time Emergency Generation (RTEG) is not considered as an alternative to transmission because it is used as an operational measure to respond in stress conditions. Hence, RTEG is considered for operational purposes rather than planning purposes. This is consistent with the ISO-NE planning practices.[46] In the ICF analysis, RTEG resources are not considered to be included as a type of active resource available to meet the additional load reduction requirement.

Exhibit 5-15
Historical Performance of Active Demand Resources in Southern New England – FCA #5

	Real Time Demand Response		Real Time Emergency Generation		Total Active Resource	
Load Zone	Summer MW	Performance (%)	Summer MW	Performance (%)	Summer MW	Performance (%)
CT	370	76	300	87	671	81
RI	75	48	98	17	173	30
SEMA	166	56	79	58	244	57
WCMA	169	67	101	72	270	69
NEMA/Boston	286	72	144	87	429	77

Source: Installed Capacity Requirement (ICR) and Related Values for the 2014/15 Forward Capacity Auction (FCA #5), ISO-NE.

[46] *New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment, April 2011, Southern New England Regional Working Group, ISO New England, pages 19 and 27.*

As shown, the real-time demand response has performed at relatively low levels in the southern New England market. The performance factors into the load reduction equivalent directly. For example, in Rhode Island, the real time demand response has performed at less than 50 percent, indicating that roughly 2 MW of active demand resource are required for every 1 MW of load reduction needed to satisfy the CLL gap.

ISO-NE has recently proposed updating the metric used to determine the performance rate for regional demand response resources for FCA #6. For FCA #6, ISO-NE is proposing to adopt performance rates based on the performance results for actual cleared resources for the first year of the FCM (summer 2010). The proposed performance rates reflect the single year of performance for actual FCM demand resources. As such, the proposed rates are more reflective of resources participating in the market, but lack the potential for variability in performance over time as the measurement is currently available for only one year. The measurement reflects results of the summer 2010 demand resource OP 4 event response for real-time demand response resources and audits for real-time emergency generation (which was not called on in 2010). The performance rates proposed for use in FCA #6 are presented in Exhibit 5-16 below. Based on the 2010 data, the real-time demand response resources in southern New England had performance levels above the historical levels used to rate resources in previous auctions.

Exhibit 5-16
Historical Performance of Active Demand Resources in Southern New England – FCA #6

	Real Time Demand Response		Real Time Emergency Generation		Total Active Resource	
Load Zone	Summer MW	Performance (%)	Summer MW	Performance (%)	Summer MW	Performance (%)
CT	273	75	203	67	476	72
RI	49	100	80	56	129	73
SEMA	150	64	72	59	222	62
WCMA	134	100	89	49	222	80
NEMA/Boston	241	68	132	60	374	65

Source: Assumptions for the Installed Capacity Requirement (ICR) for the 2015/16 Forward Capacity Auction (FCA6), August 25, 2011, ISO-NE.

Since the method proposed for FCA #6 results in performance rates that are different from the values used through FCA #5, ICF used both sets of performance rates to calculate the required amount of active demand resources in each sub-region. ICF then aggregated the resources required in each sub-region to determine the total active demand resources required in southern New England. The results are shown in Exhibit 5-17. For example, using the FCA #6 zonal performance rates, 4,157 MW are required to provide the equivalent of a 3,058 load reduction in 2015 in the Reference DR Case, resulting in an average performance rate of 74 percent for southern New England (i.e., 3,058/4,157 = 0.74). In 2020 the amount required is 5,058 MW. The amounts required are higher – 5,070 MW in 2015 and 6,287 MW in 2020 – for FCA #5 performance rates. The trend is similar in the Aggressive DR Case, with 4,099 MW and 4,495 MW required in 2015 and 2020, respectively, based on performance levels assumed in FCA #6, and 4,979 MW and 5,603 MW required in 2015 and 2020, respectively, based on performance levels assumed in FCA #5.

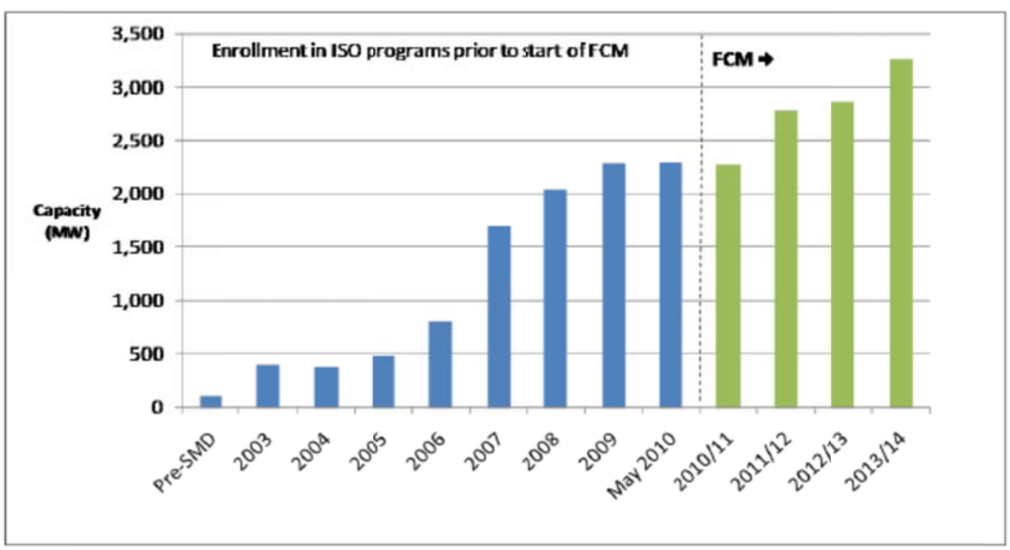
The average performance rate for southern New England varies by year and by case because it depends on both the zonal performance rate and the amount of demand resources required in each sub-region. Although the 2010 performance considerably reduces the total required resources, the reduction is driven by the change in the Rhode Island resource requirement only. Resources in Eastern and Western New England increase given the proposed performance levels. See Section I of Appendix C for additional detail on the calculation of performance rates and required active demand resources for the sub-regions in southern New England.

Exhibit 5-17
Estimated Active Demand Resources Required

Scenario	Year	Total Gap	Required Resources Based on FCA #5 Performance Factors		Required Resources Based on FCA #6 Performance Factors	
			Average Performance Rate	Resources Required to Fill Gap	Average Performance Rate	Resources Required to Fill Gap
		MW	%	MW	%	MW
Reference DR Case	2015	3,058	67%	5,070	74%	4,157
	2020	3,861	67%	6,287	76%	5,058
Aggressive DR Case	2015	2,995	60%	4,979	73%	4,099
	2020	3,417	61%	5,603	76%	4,495

To assess the reasonableness in achieving the required amount of active demand resources, ICF compared the recent active demand resource growth trends with the annual growth rates necessary to produce the required active demand resources. As shown in Exhibit 5-18, demand resources have grown rapidly in the market. Between 2007 and 2010 the annual growth rate in demand resources was approximately 10 percent.

Exhibit 5-18
Demand Resource Growth in New England



Source: Integrating Policy, Planning, and Electricity Markets In New England, ISO-NE, June 2011.

As shown in Exhibit 5-19, the cleared capacity auction levels for FCA #4 in 2013/14 reflected a total cleared demand resource level of 3,261 MW. FCA #5 results became available in June 2011. They showed total cleared demand resources of 3,468 MW. Overall, since the FCM began, demand resources have increased at an average rate of 11 percent annually. The average growth rate in demand resources after the move to a structured market in which demand resources can participate as capacity resources is similar to the average growth rate prior to implementation of the market.

Exhibit 5-19
Results of the First Five Forward Capacity Auctions

AUCTION (1)	Total Qualified Resources	Cleared Generation	Cleared Passive DR	Cleared Active DR	Cleared Active Real-Time DR	Total Cleared DR (2)	Cleared Imports	Total Capacity Acquired	Capacity Required
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
FCA #1 (2010/11)	39,165	30,865	700	970	875	2,279	933	34,077	32,305
FCA #2 (2011/12)	42,777	32,207	978	1,200	759	2,778	2,298	37,283	32,528
FCA #3 (2012/13)	42,745	32,228	1,072	1,194	630	2,867	1,901	36,996	31,965
FCA #4 (2013/14)	40,412	32,247	1298	1,363	688	3,261	1,993	37,501	32,127
FCA #5 (2014/15)	40,077	31,439	1,486	1,382	722	3,468	2,011	36,918	33,200
AAGR	0.6%	0.5%	20.7%	9.3%	-4.7%	11.2%	21.2%	2.0%	0.7%

(1) Initial results from each auction; amounts will change with monthly and annual reconfiguration auctions.

(2) Demand resource totals include a 600 MW cap on real-time emergency generation resources.

(3) Floor price is per kilowatt-month.

(4) Prorated price is per kilowatt-month.

(5) Prorated price in Maine for 2012/2013 is $2.47/kW-month.

(6) Prorated price in Maine for 2013/2014 is $2.34/kW-month.

Exhibit 5-20

Unprecedented Growth in Active Demand Resources is Required to Provide an NTA

provides a comparison of the required resources to the current levels qualified in the auctions. In 2015 the incremental active demand resources required are between 4,099 MW and 4,157 MW, based on performance rates assumed in FCA #6, implying that in a single year the total available active demand resources would need to grow by roughly 372 percent to 377 percent. Through 2020, the implied growth rate would need to be 31 percent to 33 percent per year to achieve the required incremental 4,495 MW to 5,058 MW needed above FCA #5 levels. If performance rates are based on the assumptions used in FCA #5, the level of required resources will be even higher.

Exhibit 5-20
Unprecedented Growth in Active Demand Resources is Required to Provide an NTA

Parameter	2015	2020
FCA #5 (2014/15) Qualified Active Demand Response Resources (MW)[1]	1,102	1,102
Incremental Active Demand Resources Required to Satisfy the CLL Gap (MW) [2]	4,099 – 4,157	4,495 – 5,058
Total Active Demand Response	5,201 – 5,259	5,597 – 6160
Annual Percentage Growth (%)	372-377%	31-33%

[1] The qualified resources from FCA #5 are used as a proxy for the total available demand response resources available for the summer of 2014 as of today. Total is shown for the RI, CT, and MA load zones only as the area of concern. The total qualified Real Time Demand Response Resource for all of New England is 1,667 MW. Within RI, CT and MA load zones, the qualified resources, 1,207 MW of capacity qualified, of this total, 105 MW were accepted for delist, resulting in qualified Real Time Demand Response Resources of 1,102 MW in Southern New England.

[2] Based on performance levels assumed in FCA #6. Estimates will be higher if performance levels assumed in FCA #5 are used.

Given the resources currently considered available in 2014, achieving the level of active demand resources necessary in 2015 is not reasonable. Even in the best case, where no performance adjustment is applied to active demand resources, the growth in demand response resources in the next year would need be approximately 270percent to achieve the required levels in 2015. Achieving the 2020 levels would require that these unprecedented growth levels be maintained for the next several years. Again, even in the best case, where no derate for performance is considered to apply to active demand response resources, the average annual growth between 2014 and 2020 in active demand resources would be 27 percent. Further, considering that this estimate is conservatively low in that it does not consider the quality and performance of resources assuming an increased penetration of resources, a demand alternative to satisfy the CLL load reduction levels appears unreasonable. Further discussion of quality and performance of resources is contained in the DR Duration analysis following in Section 5.3.

5.3 Demand Resource Duration Analysis

Going forward, there are a number of parameters that could result in movements in the performance rating of the active resources. For example, investment in smart grid technologies could enhance the information available to the demand resources and the grid operator and result in performance improvements that enhance active demand response reliability. Alternately, the increasing penetration of demand resources into the market could result in the need to call on the active resources more frequently, which would detract from their performance and negatively impact their reliability.

Today, roughly 7 percent (2,279 MW) of the region's capacity comes from demand resources. This is expected to grow to nearly 10 percent (3,261 MW) in 2013/14 and 10 percent (3,468MW) in 2014/15 based on forward auction results. To satisfy the resource gap in 2015, ICF identified an incremental requirement of 4,712 MW (4,373 MW active plus 339 MW passive) in 2015 and 6,956 MW (5,521 MW active and 1,435 MW passive) in 2020. Assuming the same annual growth rates for required capacity as in the past 5 auctions, the total share of demand resources would increase to 14 percent of capacity resources in 2015 and 20 percent in 2020. As demand side penetration grows, the impact on reliability of active demand response is unproven and fraught with risk of underperformance. As resources grow as a share of the capacity mix, they will be called on much more frequently than in the past and may be unwilling to perform at the prices available or may simply not be able to perform to the level called. For example, if an active demand resource is based on an air conditioning reduction, if called on to perform on a cool day the resource may simply not be operating at the levels that are required for the reduction, hence unable to perform fully. To date, demand resources have not been subject to full call to dispatch as a generation resource would be so historical performance assessments are not based on the full potential set of hours a resource might be called. However, ISO-NE recently implemented improvements to the software and communications infrastructure used between demand resources and the ISO during real-time operations. In 2011, new dispatch rules will be in place to allow operators to call on demand resources where, when, and in the amount they are needed. More complete information on demand resource performance should become available once this system is fully operational.

Given the need to understand the performance requirements of needed incremental demand side resources, ICF performed an analysis of the CLL to determine the duration and quality of resources required. This Duration Analysis was conducted to provide information that would allow an assessment of the quantity and type of resources needed to achieve the CLL levels through demand reductions.

5.3.1 Duration Analysis Approach

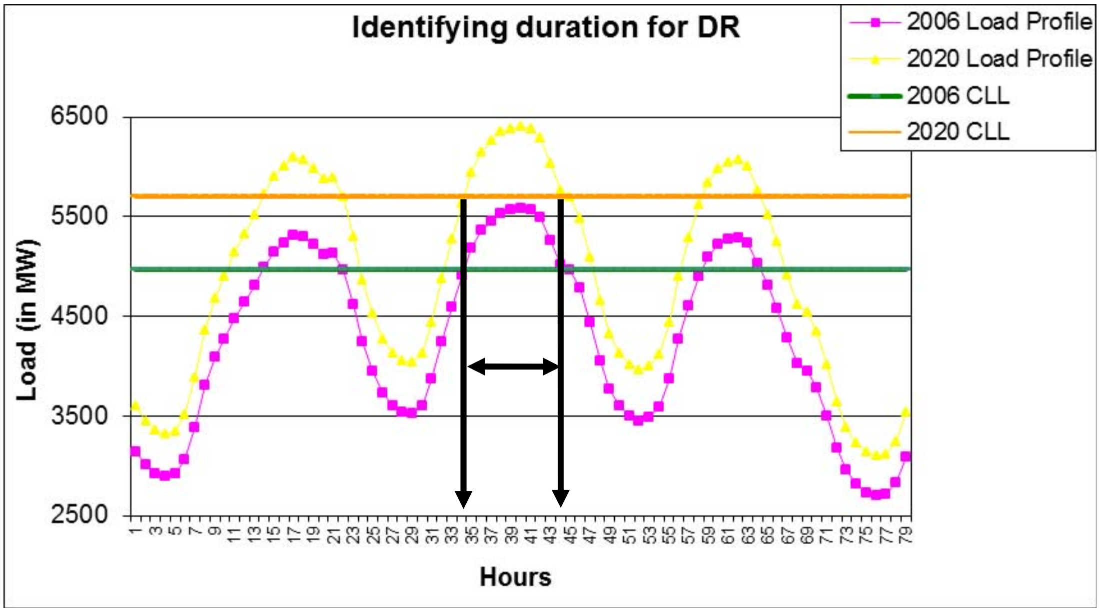
The Duration Analysis is primarily designed to focus on peak day resource requirements. However, for illustrative purposes, the analysis was extended to all hours of the year. The approach to the peak day and annual analysis are the same. These results should only be considered illustrative.

Given that the load flow analysis focuses on a single point in time only, the peak hour, it was first necessary to develop a representative load shape for 2015 and 2020. To do this, ICF relied on historical load patterns; 2006 was identified as the highest summer peak year historically. As the intent of the duration analysis is to capture the need for resources under high peak conditions, 2006 reflects a good proxy of what a forward year peak condition may look like.

Next, ICF identified sub-regional peak periods in an actual 2006 hourly load profile. The historical hourly loads were scaled to the 2015 and 2020 regional load projections (50/50) based on the 2010 CELT forecasts. 50/50 loads were considered for this duration analysis given that they are reflective of conditions considered to approximate historical normal and that resource planning, such as the FCM, is performed at the 50/50 load levels. However, reliability planning for the transmission system is based on 90/10 load levels; as such, the duration analysis considering the 50/50 loads may be considered a conservatively low estimate of the required duration for reliability purposes. Using the newly generated hourly load shapes for each year and sub-region, ICF identified all hours on the peak day, and over the course of the year, which exceeded the CLL sub-regional load levels determined in the power flow analysis. For each period, ICF identified the duration (in hours), starting from the point at which the CLL condition would first be exceeded to the last hour in which CLL would be exceeded. This allowed for the identification of the total number of events in which a demand resource would be called on to provide load reductions as well as to estimate the count of total hours (duration) for each event.

The duration was determined for both the system and the sub-regions of interest. The approach is illustrated in Exhibit 5-21, which shows illustrative 2006 and 2020 peak day load profile identifying duration of demand resources.

Exhibit 5-21
Illustrative Approach to Demand Resource Required Duration Analysis

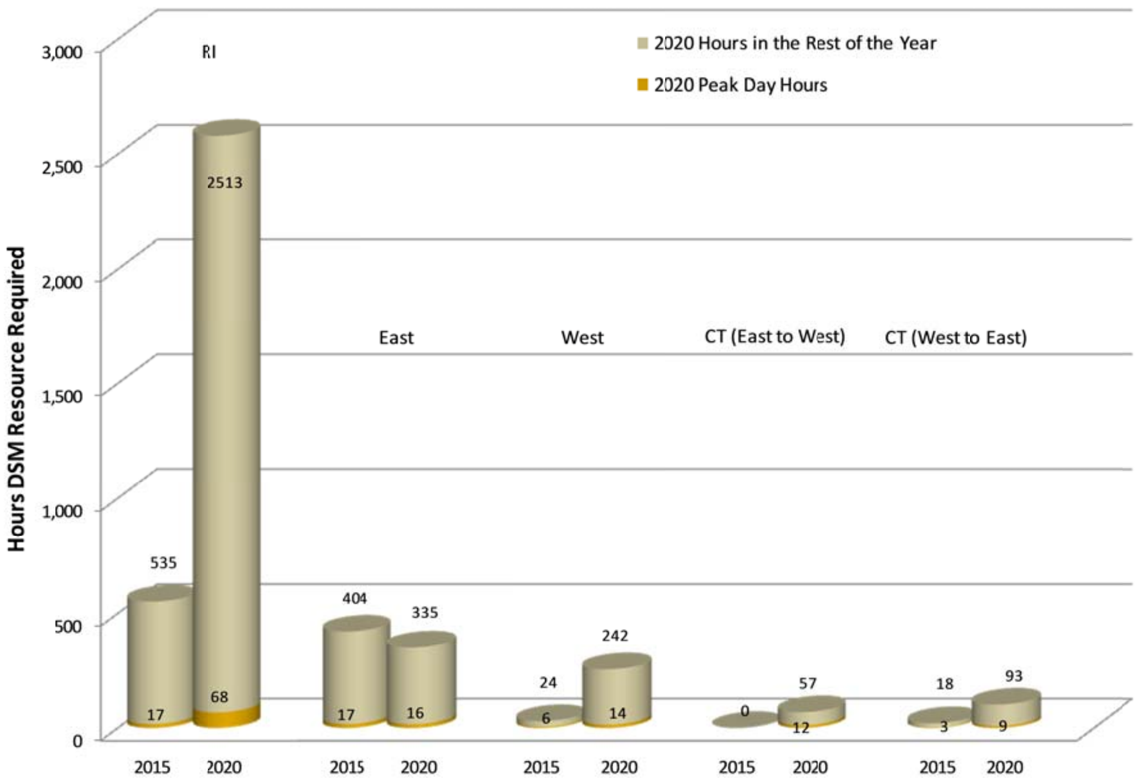


5.3.2 Results of Duration Analysis

It is important to note that the Duration Analysis is illustrative only. The assumptions concerning future conditions had to be developed with very little information regarding the historic performance of demand resources. Further, the duration analysis was based on results of load flow modeling for the summer peak condition only. As such, the load flow reflected dispatch and operational conditions expected for the summer peak, not for the off-peak, or for other seasons of the year. The duration analysis however is examined for all hours, including off-peak hours and all seasons. Since the operating procedures or availability of resources, among other things, may vary from season to season or peak to off-peak, the application of the peak condition to the load flow may not be a robust reflection of the non-peak hours. Further, a single year load shape was used to develop a forward outlook for the load conditions in 2015 and 2020. We recognize that relying on only one dispatch condition and one historical point may provide an incomplete analysis, given possible changes in conditions over time. The choice of the historical period(s) reviewed may also tend to distort the analysis depending on unique conditions which may have existed during the period selected. Further, the duration of the peak conditions themselves may vary (e.g., a period of extended hot weather may result in a peaking period pattern which differs significantly from a peak driven by a single day of extreme weather). Other factors that are not accounted for in the analysis are changes in performance of resources as penetration levels increase, and the potential for change in resource characteristics. For example, the level of smart grid applications available may alter the demand resource performance over time, demand resource product offerings may vary over time;; saturation of demand resources may also result in variations in system conditions; and responsiveness of resources). As such, the results are intended to be illustrative only. In particular, extension of the analysis past the peak condition may indicate a greater duration of need for the resource than would be the case if alternate conditions had been considered.

The results of the demand resource duration analysis are shown in Exhibit 5-22 and Exhibit 5-23. Exhibit 5-22 shows an estimate of the number of hours that DR would have to be used in southern New England to keep demand at or below the CLL and avoid violations. In 2020, the Rhode Island peak condition spans nearly 3 continuous days (68 hours). In Eastern New England, the 2020 CLL condition spans about 2/3 of the peak day (16 hours), while in Western New England it spans about 60 percent of the peak day (14 hours). Although a limited number of passive programs are able to provide around the clock savings, very few, if any, active resources would do so.

Exhibit 5-22
Estimated Duration of CLL in Southern New England



In the Rhode Island 2020 case, a need to reduce peak load by 1100 MW was identified and an incremental demand resource of 237 MW of passive resources and 2509 MW of active resources was estimated to be needed to provide this reduction under peak conditions.[47] Based on the duration analysis for 2020, a share of these resources would be required to perform for nearly consecutive days 3 days (68 hours) during the peak condition. The capacity (MW volume) identified in the single peak condition would need to be capable of providing this continuous service. Since active demand resources will tend to have patterns that peak in the daytime, this need for continuous operation implies additional types and/or quantity of resource would be to satisfy the duration requirement. Passive resources will provide some evening and

[47] *The active DR estimates included here reflect the historical performance levels for real-time active demand response and real-time emergency generation in Rhode Island.*

nighttime savings, however active resources tend to be much more concentrated in daytime hours. The ability to satisfy the duration requirements that extend past the peak load hours, as is the case in all the sub-regions considered for the southern New England area, is questionable given the high concentration of peak period resources required to meet peak load reduction requirements.

On an annual basis, the results of the duration analysis illustrate a potentially significant need to rely on demand resources throughout much of the year in Rhode Island. For example, DR would be called in more than 500 hours during the year in 2015, and in more than 2500 hours in 2020.

The number of hours is lower for resources in Eastern NE and Western NE, but is still in the hundreds of hours in 2020.

Exhibit 5-23 shows the number of events, that is, the number of times that demand resources would have to be activated, by month in 2020. It shows that DR would be activated year round in Rhode Island, with the fewest events at 5 each in the shoulder months of April and May. In the remaining months demand resources will be activated more than 20 times each month. Demand resources would be activated fewer times in Eastern NE and Western NE, but at least 30 times during the summer in each sub-region.

Exhibit 5-23
Estimated Number of CLL Events in 2020

Month	RI	East	West	CT (East-West)	CT (West-East)
January	36	0	0	0	0
February	41	0	0	0	0
March	36	0	0	0	0
April	5	0	0	0	0
May	5	0	0	0	0
June	27	8	6	0	1
July	31	19	18	4	6
August	25	7	6	3	3
September	25	0	0	0	0
October	24	1	0	0	0
November	26	0	0	0	0
December	38	0	0	0	0
Total	**319**	**35**	**30**	**7**	**10**

The number of events exceeds the levels anticipated by ISO-NE in early auction periods. For example, qualified resources would need to be called on every day in Rhode Island in the summer months and for over half the month in the East and West areas. One must account for the frequency and duration of the requirement which indicates that the demand resource must be available in every month of the year at very high levels, sometimes called to perform multiple times a day, and sometimes called to perform for several days in a row (during daytime and nighttime hours). Incorporating these requirements would effectively indicate that the demand resource in Rhode Island needs to be available around the clock and around the year. Such a solution is simply not a realistic alternative to accomplish the load reductions required.

5.4 Conclusion

ICF evaluated the current outlook for growth in passive demand resources including energy efficiency and distributed generation resources to determine a reasonable projection for growth in each state. This estimated level of passive demand resource was then compared to the estimated CLL discussed in Chapter 4. The comparison indicated that despite the addition of an aggressive level of estimated potential passive demand resources, the load would exceed the CLL, all else equal. ICF estimated the additional active demand resources required to provide the additional load reduction needed to maintain the CLL. ICF concluded that to achieve this additional load reduction, an unprecedented amount of growth in active demand resources would be required.

ICF further estimated the duration requirements that would be applied to active demand resources to maintain the CLL levels, not only at the single peak hour, but throughout the year. The results of the duration analysis indicate that the number of times the active demand resources would be called on over the year would be more than 30 times in all markets considered, with much more significant calls in Rhode Island. Further, active demand resources would need to be available and commit to operating around the clock in peak conditions to maintain the CLL in all years. Based on this analysis, ICF concluded that the type of operational requirements placed on the active demand resources would be extreme and difficult to satisfy.

CHAPTER 6
Generation Alternatives

When sited in the right locations, central generation stations can resolve some of the reliability violations and potentially defer or eliminate the need for a transmission project. ICF reviewed the New England Generation Interconnection Queue (Interconnection Queue) as of April 1st, 2011 for proposed generation facilities in southern New England that could be used in developing an NTA to the Interstate Reliability Project.

This chapter describes the generation resources identified as potential NTAs, and their impact on the criteria violations in the base power flow cases.

6.1 Identification of Generation Alternatives

The Interconnection Queue is the best available indication of where generation is likely to be sited in the near future. The Interconnection Queue includes planned and proposed generation facilities in the ISO New England zones. From the Interconnection Queue, ICF selected generation resources planning to interconnect into the load zones in southern New England and grouped them into three categories based on the likelihood of construction. The categories were:

- **Category 1:** Facilities with completed Interconnection Agreements. These facilities have gone through various studies and all the steps in the approval process and were considered very likely to be developed.
- **Category 2:** Facilities with PPA approval in accordance with Section I.3.9 of the ISO New England Transmission, Markets and Services Tariff, but excluding facilities with completed Interconnection Agreements (Category 1).
- **Category 3:** All facilities in the Interconnection Queue, but excluding facilities with completed Interconnection Agreements (Category 1) and Section I.3.9 approval (Category 2). Units in Category 3 were considered the ones with the lowest probability of being developed.

Generator capacities were adjusted from the summer capacity in the Interconnection Queue to reflect the actual capacity expected to be available during a summer peak period. In particular, in line with ISO-NE's treatment of wind resources, ICF assumed that the contribution of wind resources to summer peak capacity would be 10 percent of their installed capacity.

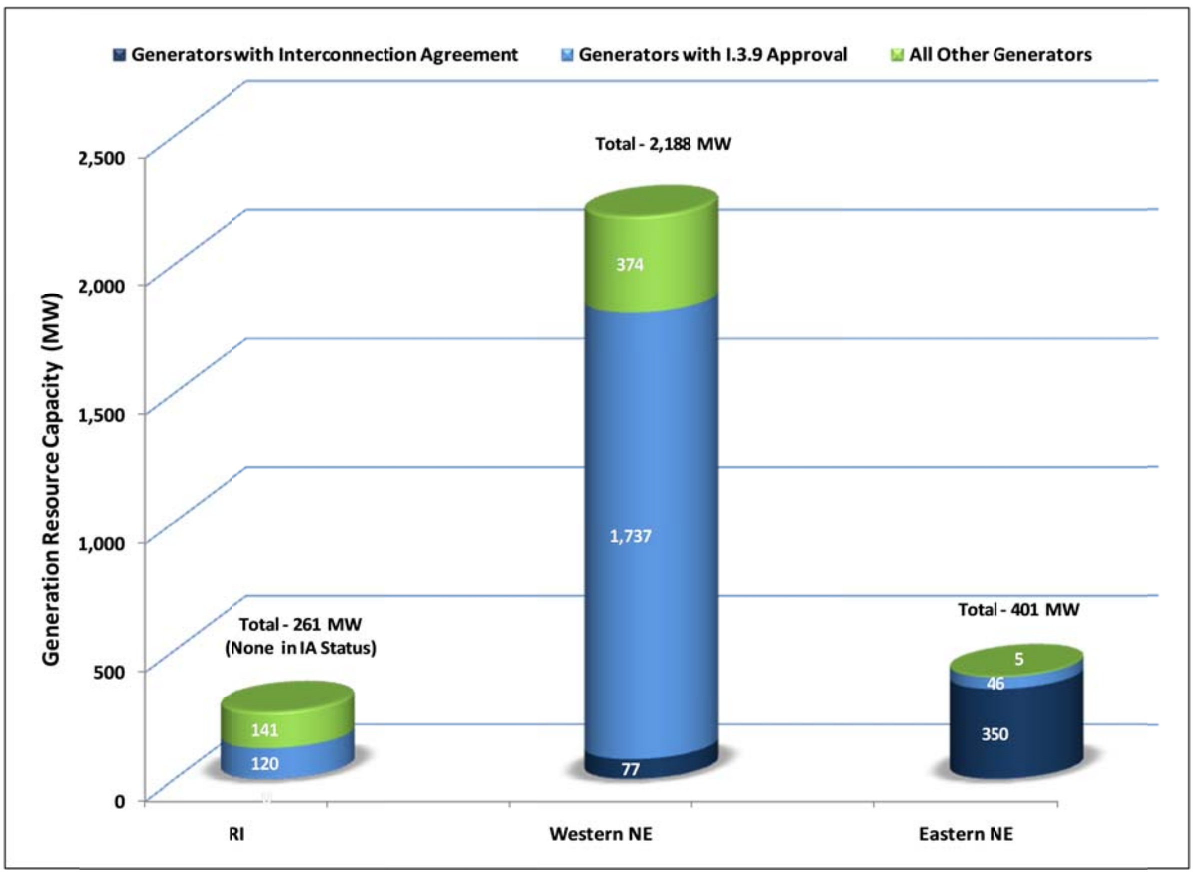
The ISO-NE Interconnection Queue identifies 2850 MW of potential generation capacity in southern New England (see Exhibit 6-1). Of this capacity, 2,188 MW, or approximately 77 percent of the total, would be sited to the west of the New England East–West interface, in Western NE (see Exhibit 6-2). Approximately 401 MW (14 percent) would be located to the east of the interface, in Eastern NE, and 261 MW (9 percent) would be located in Rhode Island. As explained in Chapter 3 GRI, which includes the Rhode Island load zone, may be considered to be on either side of the interface, depending on the direction of the flow across the interface.

Exhibit 6-1
Potential Southern New England Generation in the ISO-New England Interconnection Queue

Category	Description	Capacity (MW)
Category 1	Generators with completed Interconnection Agreements	427
Category 2	Generators with I.3.9 approval (excluding Category 1)	1,904
Category 3	All generators in the Interconnection Queue (excluding Categories 1 and 2)	520
	Total	**2,850**

Source: ISO New England Generation Interconnection Queue as of April 1, 2011.

Exhibit 6-2
Potential NTA Generation Capacity in the Sub-regions of Southern New England



Source: ISO New England Generation Interconnection Queue as of April 1, 2011.

Exhibit 6-3 shows the available capacity by technology type in each of the sub-regions. A summary of the list of generators proposed in each sub-region is provided in Appendix D.

Exhibit 6-3
Potential Southern New England Generation Technology Types

Generation Facility Type	Eastern NE Capacity (MW)	Western NE Capacity (MW)	RI Capacity (MW)	Total Capacity (MW)
Steam Turbine (Coal or Biomass)	3	168	38	209
Combined Cycle	350	1,908	166	2424
Combustion Turbine	0	15	0	15
Wind	49	6	56	111
Hydroelectric/ Pumped Storage	0	91	0	91
Total	**401**	**2,188**	**261**	**2,850**

6.2 Approach

The approach used to analyze the generation NTAs was similar to that used in the Needs Assessment (see Section 3.1.4). A power flow analysis was performed to assess the ability of the generation resources to resolve the reliability criteria violations observed in the needs assessment and develop a generation-only NTA solution.

First, generation facilities from Category 1 were added to the 2015 and 2020 base power flow cases, and the cases were analyzed under N-1 and N-1-1 contingency conditions similar to the Needs Assessment. The results were compared to those from the Needs Assessment, and any remaining or new thermal violations were noted. If any thermal violations remained, then generation facilities from Category 2 were added to those cases and the contingency analysis and review of results was repeated. If thermal violations persisted after addition of Category 2 resources, the process was repeated with Category 3 resources.

Further, to ensure that the choice of units did not affect the results, ICF developed two approaches to prioritize and select generators in southern New England from the Interconnection Queue. In the first approach, generators were prioritized by the likelihood of proceeding to actual construction based on their stage of permitting, status of financing, and other related factors. Units that had a higher likelihood of proceeding to construction were selected first. In the second approach, generators were prioritized based on ICF's engineering judgment of their impact on the reliability violations and their ability to relieve the violations. Units that would be most effective at relieving the violations were selected first. Demonstrating that the choice of generators would not bias the results was important only if all violations could be resolved with an NTA developed from a partial selection of generators. If all available generators had to be used to develop the NTA, the order in which units were selected would not be an issue.

Exhibit 6-4 shows the level of generation NTA capacity added in southern New England in 2015 and 2020. In 2015 a partial selection of generators was used, so ICF applied the prioritization and selection criteria to demonstrate that the choice of units would not affect the overall results. The generation NTA capacity in southern New England added to the cases in 2015 was 1,302 MW in the first scenario and 1,281 MW in the second. In 2020 all generation capacity in southern New England available from the Interconnection Queue, totaling 2,850 MW, was added to the power flow cases. The capacity added in each sub-region in 2015 is shown in Exhibit 6-5 for Scenario 1 and Exhibit 6-6 for Scenario 2.

Exhibit 6-4
Southern New England Generation NTA Capacity Additions – 2015 and 2020

Category	2015 Capacity Additions (MW)		2020 Capacity Additions (MW)
	Scenario 1[1]	Scenario 2[2]	
Category 1	427	427	427
Category 2	729	708	1,904
Category 3	146	146	520
Total	**1,302**	**1,281**	**2,850**

[1] Only a partial selection of generators in the Western NE sub-region was required for the NTA in that sub-region. Generators in Category 2 were prioritized by the likelihood of proceeding to actual construction, based on the stage of permitting, status of financing, and other related factors. Units that had a higher likelihood of proceeding to construction were selected first. The 510 MW Meriden Power Plant and an uprate of 52.5 MW at Northfield Mountain pumped storage plant were the only units selected in Category 2. No units were selected in Category 3.

[2] Only a partial selection of generators in the Western NE sub-region was required for the NTA in that sub-region. Generators in Category 2 were prioritized by the likelihood of proceeding to actual construction, based on the stage of permitting, status of financing, and other related factors. Units that had a higher likelihood of proceeding to construction were selected first. The 489 MW Towantic Power Plant and an uprate of 52.5 MW at Northfield Mountain pumped storage plant were the only units selected in Category 2. No units were selected in Category 3.

Exhibit 6-5
Southern New England Generation NTA Capacity Additions – 2015 Scenario 1

Category	Eastern NE Capacity (MW)	Western NE Capacity[1] (MW)	RI Capacity (MW)	Total Capacity (MW)
Category 1	350	77	-	427
Category 2	46	563	120	729
Category 3	5	-	141	146
Total	**401**	**640**	**261**	**1,302**

[1] Only a partial selection of generators in the Western NE sub-region was required for the NTA in that sub-region. Generators in Category 2 were prioritized by the likelihood of proceeding to actual construction, based on the stage of permitting, status of financing, and other related factors. Units that had a higher likelihood of proceeding to construction were selected first. The 510 MW Meriden Power Plant and an uprate of 52.5 MW at Northfield Mountain pumped storage plant were the only units selected in Category 2. No units were selected in Category 3.

Exhibit 6-6
Southern New England Generation NTA Capacity Additions – 2015 Scenario 2

Category	Eastern NE Capacity (MW)	Western NE Capacity[1] (MW)	RI Capacity (MW)	Total Capacity (MW)
Category 1	350	77	-	427
Category 2	46	542	120	708
Category 3	5	-	141	146
Total	**401**	**619**	**261**	**1,281**

[1] Only a partial selection of generators in the Western NE sub-region was required for the NTA in that sub-region. Generators in Category 2 were prioritized by the likelihood of proceeding to actual construction, based on the stage of permitting, status of financing, and other related factors. Units that had a higher likelihood of proceeding to construction were selected first. The 489 MW Towantic Power Plant and an uprate of 52.5 MW at Northfield Mountain pumped storage plant were the only units selected in Category 2. No units were selected in Category 3.

6.3 Results

ICF's analysis shows that no practically feasible generation NTA is available to resolve the southern New England reliability criteria violations that Interstate addresses. Despite adding all the southern New England generation in the ISO-NE queue the generation NTA did not resolve the regional reliability problems.

Exhibit 6-7 summarizes the results of the generation NTA analysis in southern New England. It shows the number of reliability criteria violations in southern New England after implementation of the generation NTA in 2015 and 2020, compared to the violations in the needs assessment. Multiple contingencies could cause overloads on a single transmission element. In 2015, the generation NTA reduced the thermal violations in the needs assessment by 56 percent, from 206 in the base power flow cases to 90 in the generation NTA cases. In 2020 the violations were reduced by 53 percent, from 6,029 in the base power flow cases to 2,817 in the generation NTA.

Exhibit 6-7 also shows the number of elements overloaded in 2015 and 2020. In this instance, the number of elements overloaded in 2015 decreased by 15 percent; from 20 elements in the Needs Assessment to 17 elements after implementation of the generation NTA. It decreased by 42 percent in 2020, from 53 in the Needs Assessment to 31 after implementation of the generation NTA.

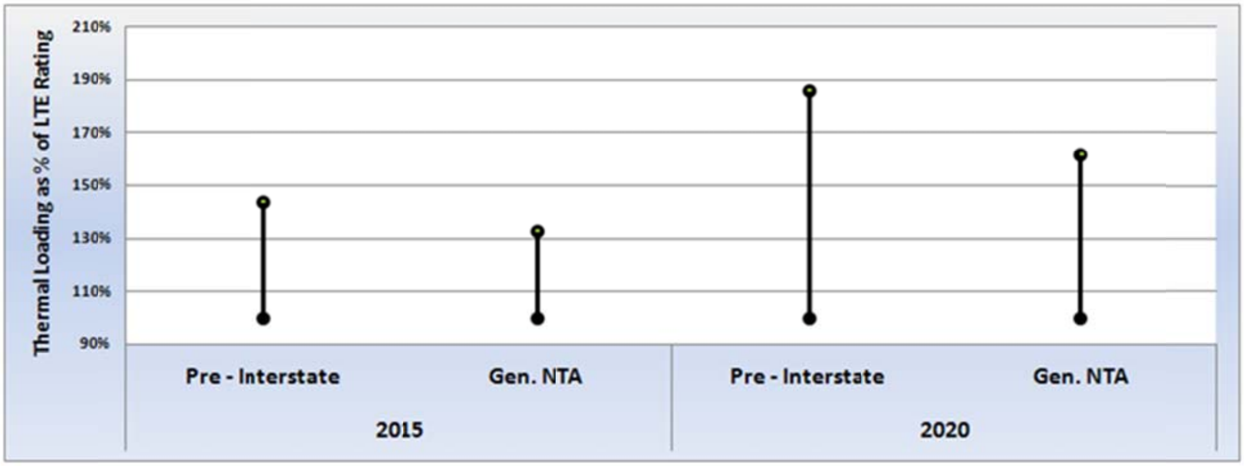
Exhibit 6-7
Summary of Reliability Criteria Violations for Generation NTA

Year	Number of Thermal Violations			Number of Elements Overloaded		
	Needs Assessment	Generation NTA	Percent Reduction	Needs Assessment	Generation NTA	Percent Reduction
2015	206	90	56%	20	17	15%
2020	6,029	2,817	53%	53	31	42%

The severity of the thermal violations is shown in Exhibit 6-8. The generation NTA was more effective in reducing the number of violations than the severity of violations. Many of the most severe overloads still remained. In 2015, some transmission facilities exceeded their thermal limit ratings by 30 percent. In 2020, some violations were more than 60 percent higher than the rating of the facilities.

(See Section III of Appendix A for a list of the overloaded transmission facilities.)

Exhibit 6-8
Range of Reliability Criteria Violations in Southern New England – Generation NTA



6.4 Implementation Challenges

It is theoretically possible to design a hypothetical NTA to the Interstate project given unlimited resources and the necessary time to develop new generation. However, such an NTA would be challenging to implement compared to the Project. The reasons include the large scope required for an NTA solution, the absence of the procedures required to attract the resources, the risk of over-reliance on demand resources, and risks associated with the high cost of an NTA solution. These are discussed in more detail below.

6.4.1 NTA Implementation Scope

The hypothetical NTA likely would involve numerous power plants and demand resources at multiple locations. As the number of sub-projects multiplies, the potential for unexpected problems in terms of permitting, financing, construction, testing, and operation increase. Approximately 75 percent of the projects in the Interconnection Queue fail to be commercialized. Also, demand-only or combination NTA would require the co-ordination of many entities, most responding to financial incentives, without experience in or commitment to solving transmission security problems. As the scope of the NTA solution increases and the economic benefit of NTAs decreases, e.g., decreases in the electrical energy prices per MW added, the ability to implement a multi-state NTA decreases. In contrast, Interstate is a single integrated solution to multiple violations that occur over a broad area of the southern New England electric system. It would employ proven technology and would be administered by ISO-NE, a centralized expert authority. Also, the Project would be constructed by experienced transmission owners.

6.4.2 Multi-State Implementation

NTA implementation of the scope required is an especially difficult problem because it involves three states. There are no clearly established and centralized multi-state procedures for NTA implementation. Each state must have the procedures and structures such as contracting and permitting in place to implement the NTA. Also, the states must be able to effectuate long-term contracts with NTA providers, especially providers of supply based NTAs. This is because NTAs will most likely require contracts and programmatic support. Even if an NTA could be found, it would be a challenge for a state to pursue a contract in the absence of the appropriate procedures and structures, even if the state was interested. In contrast, there is a centralized process for developing transmission.[48]

6.4.3 Risk of Over-Reliance on Demand Resources

ISO-NE already relies heavily on demand resources. Further reliance on demand resources via a demand-only or combination NTA increases the concerns related to the risks of this reliance:

- In FCA #5, ISO-NE procured 11 percent of its resource requirements via demand resources. New market rules such as the elimination of the FCM price floor (scheduled for FCA #8 in 2013) and the potential retirement of power plants due to age and/or new environmental restrictions will tend to eliminate supply resources. In a scenario in which excess supply resources were to leave the market (i.e., about 3,700 MW or about 2,400 MW with the potential loss of Vermont Yankee and the loss of Salem Harbor), demand resources would contribute fully 80 percent of ISO-NE local reserves. At present, only 60 percent of the demand resources are active.[49]
- Reliance on demand resources in such a scenario would become more frequent.[50] There may be a risk that the New England region could be exposed to significant attrition of active demand resources by the "fatigue" of being called on extensively and repeatedly in hot weather to decrease load. Under the FCM, interruptible load contracting is for a single year, so that a party who agrees to service interruptions can leave the DSM program on short notice and with little or no financial penalty relative to never having participated. Although there is as yet

[48] To the extent that stakeholder responses to market signals are not forthcoming or adequate to meet identified system needs, the planning process requires the ISO, through the open stakeholder process, to conduct subsequent transmission planning to develop regulated transmission solutions that determine transmission infrastructure that can meet the identified needs. The ISO does not, however, have the authority to build needed resources or transmission. Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 14.

[49] Historically, reserve capacity has been controlled by system operators. Hence, systems are in place for determining the operational status and performance of the plants. In contrast, passive demand resources are not controlled by operators and not subject to the same tracking systems. Hence, the operators might not be aware that there are limitations on the use of these resources during periods when reserves are required to maintain service, and, hence, there are less reserves available. For example, distributed generation included as a passive demand resource is not under operator control and might fail to operate. Also, the estimates of the amount of energy efficiency achieved might be in error, and operators may not have sufficiently accurate information that this type of reserve is not available.

[50] In the event of a contingency additional resources are required. To the extent that NTA resources are supply, then the region is less reliant on demand resources – e.g., active DR is not used. Conversely, if NTA resources are all demand resources, then the demand resource usage will be added to the amount and frequency of demand resources called upon separate from the existence of a contingency.

no body of data by which the effect of this fatigue factor can be documented and measured, it is a serious concern.

- In order to make agreements to accept interrupted service reliable enough for large scale use in an NTA, new program features would most likely be required. These could include longer contract periods with longer notice periods required for withdrawal to accommodate the longer lead time for transmission relative to generation; greater penalties for non-performance; technology to allow system operators to interrupt service to a participant without relying on the participant's voluntary compliance; and greater evergreen provisions (e.g., legal provisions to obligate the new owner of a contracted house or business to honor the contract).

6.4.4 Supply NRA Risks

Supply NTAs (new generation) would likely involve Contracts For Differences under which the ratepayers undertake to make up the shortfall that may occur if a new plant's revenue requirements exceed its market-based earnings in the ISO-NE markets. ICF estimated that the capital costs for the generation component of the combination NTAs could be up to approximately 2.4 billion dollars for one of the combination generation and demand resource scenarios analyzed (see Appendix E). ISO-NE markets can have volatile prices. This creates large risks for ratepayers that the Contracts For Differences payment to the power plant will have to be large.

6.4.5 Capital Costs

Even though no feasible NTA was found, the hypothetical demand and supply NTAs examined had capital costs of at least $15 billion or roughly 30 times the cost of the Interstate Project. The supply costs were based on the capital costs of new gas-fired combined cycles, the most common new power plant type in ISO-NE. The passive DR cost estimate is based on program cost estimates from the states. Active demand resource costs were based on the annual payment required to obtain voluntary consent to interruption. This annual cost was based on estimates of the costs to consumers of interruption of service referred to as the Value of Lost Load (VoLL) and estimated frequency of interruption. Annual estimated VoLL costs were capitalized at a utility cost of capital.

ICF did not examine the potential benefits of NTAs because these high costs decreased the likelihood that benefits would exceed costs. Also, and more importantly, the analysis was not needed due to the failure of the NTAs to meet the identified need by resolving the thermal violations in southern New England solved by the Project.

6.4.6 NTA Cost Allocation Versus Interstate Cost Allocation

The ISO-NE-wide transmission planning process that concluded Interstate is needed will likely result in a region-wide allocation of transmission costs based on each state's share of New England's load.

6.5 Conclusions

ICF's analysis shows that there is no practically feasible generation-only NTA that can resolve the southern New England reliability problems identified by ISO-NE. ICF made the optimistic assumption that all generation in the Interconnection Queue would be constructed and be available by 2015, providing a total summer capacity of 2,850 MW. The generation-only NTA resolved only 56 percent of the violations in 2015 and 53 percent in 2020. The number of elements overloaded decreased by only 15 to 42 percent. Thus, the available generating capacity in southern New England was not sufficient to relieve all the thermal violations. In contrast, the Interstate Project resolves all violations and improves reliability in southern New England.

Further, implementing an NTA from generation resources provides implementation challenges including exposure of ratepayers to high volatile costs associated with CFDs. Also, ISO-NE reports that historically only about 25 percent of the generation in the ISO-NE queue becomes commercialized. Thus, there are significant risks of failure.

CHAPTER 7
Combined Generation and Demand Alternatives

Generation resources currently in the ISO-NE Interconnection Queue, reflective of available new generation capacity that could enter the New England power market within the 5-year and 10-year planning horizon, reduced the thermal violations in southern New England but did not resolve all violations. ICF did not find a feasible NTA solution composed entirely of generation resources, i.e., potential generation alone could not solve the regional reliability problems.

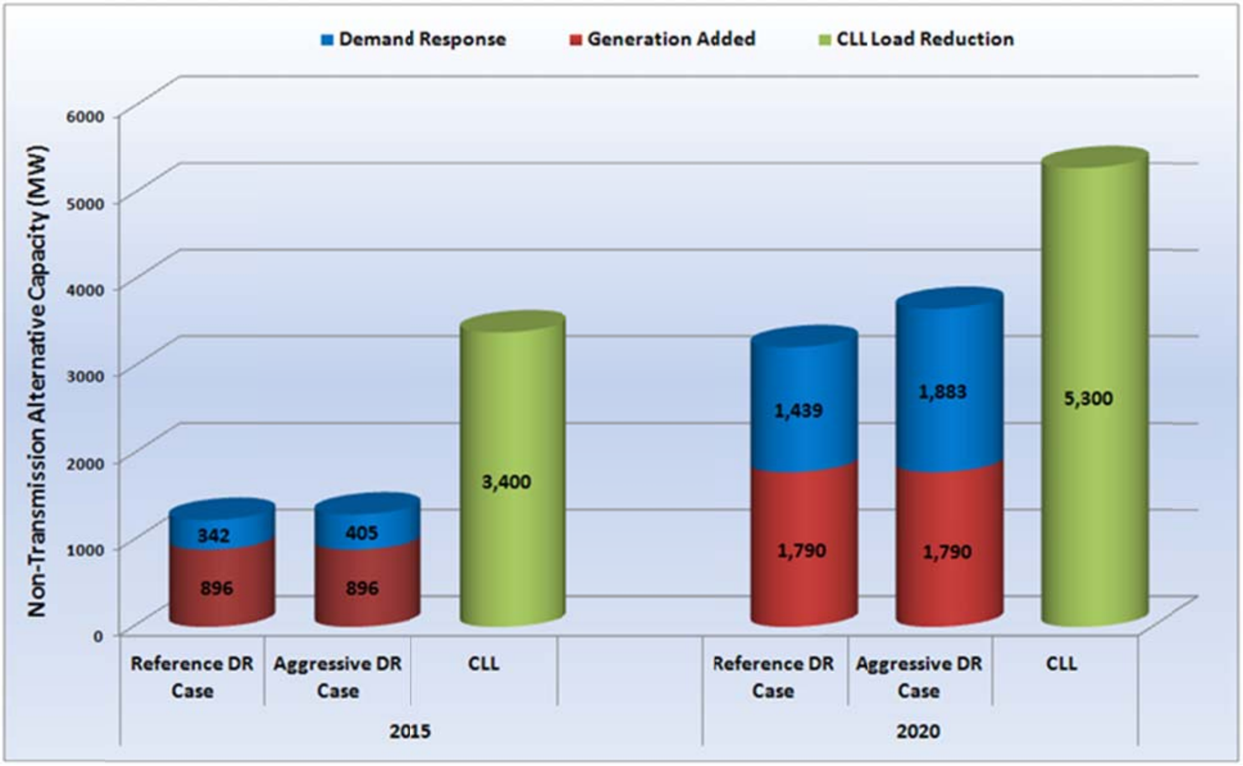
Following its demand-side-only and generation-only analyses, ICF sought to develop a feasible NTA solution that combined generation with demand side resources. ICF supplemented the generation NTA with the projected passive demand resources identified in Chapter 5 to develop a combination generation and passive demand resource NTA. ICF then analyzed the combination to determine if it would provide a feasible NTA solution. Having found that it would not, ICF considered whether the further addition of active demand resources could provide a solution.

This chapter presents ICF's analysis of combinations of generation and demand resources as potential NTAs.

7.1 Results

Exhibit 7-1 shows the incremental amount of generation and passive demand resources used to develop the Combination NTAs. The amounts shown are incremental to the capacity already included in the base power flow cases prepared by ISO-NE, which include the generation and demand resources that cleared in FCA #4. The identification of generation and demand resources for inclusion in the Combination Cases reflected a refinement to the calculation of necessary generation from the approach used in the Generation-Only NTA analysis to account for the interaction of generation resources and demand reductions. In the Combination Case, ICF first assumed the passive demand resources would be available. Next, generation was added in an attempt to address the remaining violations. This resulted in a reduced amount of generation resources in the Combination NTA Cases compared to the amount included in the Generation NTA Cases discussed in Chapter 6. In 2015, 896 MW of new generation capacity was added in southern New England. This was combined with 342 MW of passive DR in the Reference Case and 405 MW of passive DR in the Aggressive Case. In 2020, 1,790 MW of new generation capacity was combined with 1,439 MW of Reference Passive DR Case and 1,883 MW in the Aggressive Passive DR Aggressive Case.

Exhibit 7-1
Incremental Supply and Demand Resource Capacity in Combination NTA Cases



Exhibits 7-2 and 7-3 show the results of the combination NTA analysis. Exhibit 7-2 shows the number of reliability criteria violations in southern New England after implementation of the Reference DR Combination NTA, compared to the violations in the Needs Assessment. Multiple contingencies could cause overloads on a single transmission element. The Reference DR Combination NTA reduced the number of thermal violations in 2015 from 206 in the Needs Assessment cases to 77. These include multiple violations on the same element as a result of different contingencies. In 2015, 16 different transmission facilities are overloaded in the Reference DR Combination NTA, compared to 20 in the Needs Assessment. This means that in 2015 multiple contingencies cause 77 violations on 16 facilities when the Reference DR Combination NTA is implemented. In 2020, the violations are reduced from 6,029 in the Needs Assessment cases to 124 in the Reference DR Combination NTA. The overloads in the Combination NTA occurred on 19 transmission elements, compared to 53 in the Needs Assessment.

Exhibit 7-3 shows the results for the Aggressive DR Combination NTA. The violations are reduced slightly relative to the Reference DR Combination NTA. In 2015, the Aggressive DR Combination NTA reduces the number of violations from 206 in the Needs Assessment cases to 72. These overloads occurred on 16 transmission elements, compared to 20 in the Needs Assessment. In 2020 the number of violations reduces from 6,029 in the Needs Assessment to 84 in the Aggressive DR Combination NTA. The number of overloaded transmission elements also decreases from 53 in the Needs Assessment to 17 in the Aggressive Passive DR Combination NTA in 2020.

Exhibit 7-2
Summary of Reliability Criteria Violations for Reference DR Combination NTA

Year	Number of Thermal Violations			Number of Elements Overloaded		
	Needs Assessment	Combination NTA	Percent Reduction	Needs Assessment	Combination NTA	Percent Reduction
2015	206	77	63%	20	16	20%
2020	6,029	124	98%	53	19	64%

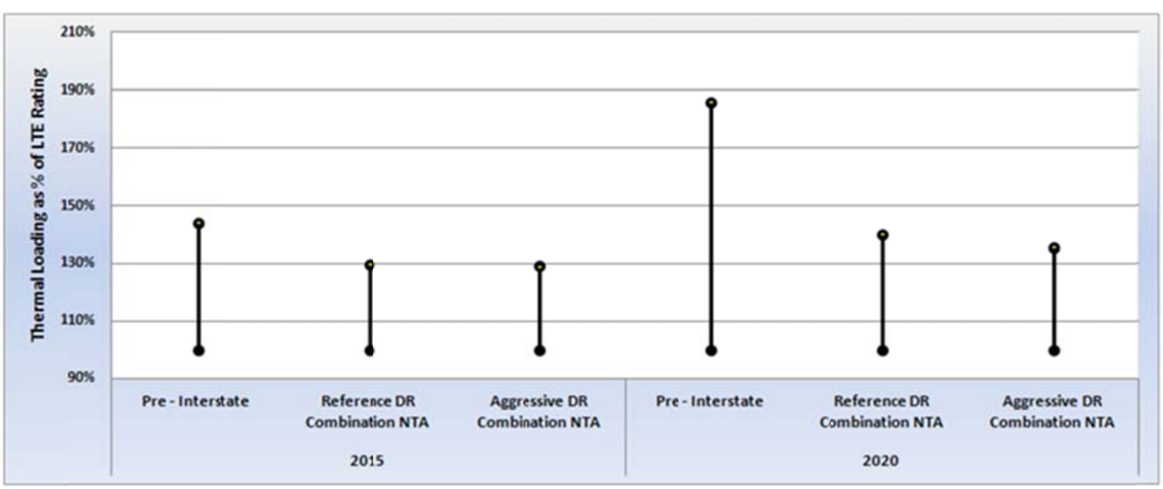
Exhibit 7-3
Summary of Reliability Criteria Violations for Aggressive DR Combination NTA

Year	Number of Thermal Violations			Number of Elements Overloaded		
	Needs Assessment	Combination NTA	Percent Reduction	Needs Assessment	Combination NTA	Percent Reduction
2015	206	72	65%	20	15	25%
2020	6,029	84	99%	53	17	68%

The severity of the thermal violations is shown in Exhibit 7-4. The combination NTA reduced the number of violations significantly. It was also effective in reducing the severity of violations. However, many severe violations still remained. For example, in all the combination NTAs, some transmission facilities exceeded their limits by approximately 30 percent.

ICF's analysis shows that a combination of proposed generation resources and aggressive estimates of passive demand resource is not an effective NTA. More detailed results are presented in Section III of Appendix B.

Exhibit 7-4
Range of Reliability Criteria Violations in Southern New England – Combination NTA



7.2 Additional Active Demand Resources Required to Eliminate Identified Violations

Similar to the CLL analysis described in Chapter 4, ICF determined the additional load reduction required in the Combination NTAs to resolve all the thermal violations that Interstate addresses. ICF then determined the additional active demand resource capacity that would provide the required load reduction. Exhibit 7-5 shows the load reduction required to produce a combination NTA solution.[51]

Exhibit 7-5
Combination Case Incremental Required Load Reduction to Achieve an NTA in Southern NE – 2015 and 2020

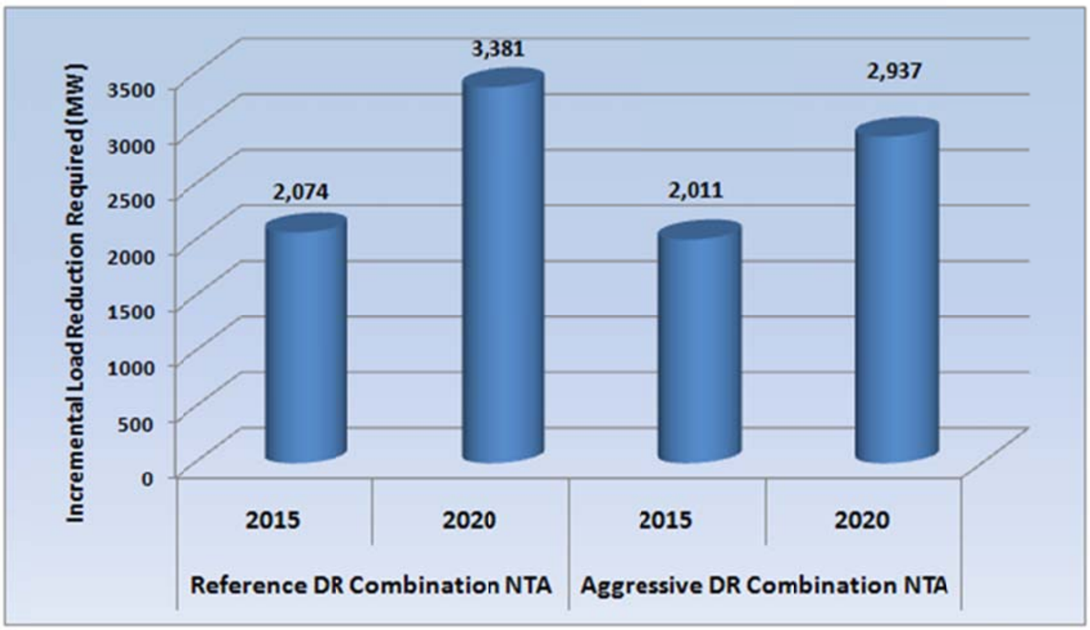


Exhibit 7-6 compares the load reduction required in the combination NTAs to those estimated for the demand NTAs discussed in Chapter 5. The load reduction required in the combination NTAs is significantly lower than that in the demand NTAs. In 2015 the load reduction required in each combination NTA is approximately 1,000 MW lower than that in the corresponding demand NTA. For example, the demand reduction required in the Reference DR Demand NTA is 3,058 MW, compared to 2,075 MW in the Reference DR Combination NTA. In 2020 the load reduction required in each combination NTA is approximately 500 MW lower than that in the corresponding demand NTA. The results show, however, that the achievable passive demand resources and generation resources potentially available in the Interconnection Queue will not be sufficient to produce a combination NTA solution that would resolve all the violations that Interstate addresses.

[51] *The Combination NTA Cases are inclusive of load reductions for the ICF estimated Reference DR and Aggressive DR Cases and further include active demand resources equivalent to FCA #4 results. Estimates are incremental to these already assumed DR savings.*

Exhibit 7-6
Load Reduction Needed to Fully Alleviate Thermal Overloads in 2015 and 2020

	Additional Load Reduction Required to Alleviate All Thermal Violations (MW)							
	2015 Case				2020 Case			
	Reference	Aggressive	Combination Reference	Combination Aggressive	Reference	Aggressive	Combination Reference	Combination Aggressive
Rhode Island	753	739	553	539	939	865	738	665
Western New England	214	187	26	0	920	762	158	0
Eastern New England	2,092	2,069	1,495	1,472	2,003	1,790	2,484	2272
Southern New England	3,058	2,995	2,075	2,011	3,861	3,417	3,382	2,937

NOTE: Totals may not sum due to rounding.

In 2015 the gap in the combination NTA cases varies from 2,011 MW in the Aggressive DR Combination NTA to 2,075 MW in the Reference DR Combination NTA. In 2020 it increases to 2,937 MW in the Aggressive DR Combination NTA and 3,382 MW in the Reference DR Combination NTA.

Potential avenues to fill the gap include increased funding levels for passive programs, and increased active demand response resources. Given that the Aggressive DR Case did not satisfactorily resolve the reliability overloads, ICF assumed the additional demand reductions would have to be satisfied with active demand resources. ICF estimated the amount of active demand resources required to achieve the load reduction needed for an NTA solution.

Unlike traditional generating resources with many decades of historic data for analysis or energy efficiency resources with long histories available, the long-term projections of active demand resources involve greater forecasting uncertainty. While the recent FCM auctions have revealed significant participation of demand response programs, the long-term availability of these resources remains uncertain. Contributing to the difficulty of estimating the long-term potential for active demand resources are factors such as response fatigue and economic-base participation rates, To provide a range of the potential requirement for incremental active demand resources, ICF relied on the performance factor ratings reported by ISO-NE for FCA #5 and also considered the impact of the performance factor ratings proposed by ISO-NE for FCA #6. The capacity of each active demand resource is derated by the performance rate when determining the amount of active demand resources needed to provide the required load reduction.

ICF calculated the performance rate and the required amount of active demand resources in each sub-region, and then aggregated the sub-regional values to determine the values for southern New England. Exhibit 7-7 presents the amount of active demand resources required to produce an NTA solution, based on performance rates assumed in FCA #5 and FCA #6. To achieve an NTA solution, the required incremental active demand resource would be a minimum of 2,754 MW to 2,835 MW in 2015 and 4,083 MW to 4,667 MW in 2020, based on FCA #6 performance rates. The required amounts will be higher if FCA #5 performance rates are assumed.

The average performance rate for southern New England varies by year and by case because it depends on both the sub-regional performance rate and the amount of demand resources required in each sub-region. Although the 2010 performance considerably reduces the total required resources, the reduction is driven by the change in the Rhode Island resource requirement only. Resources in Eastern and Western New England increase given the proposed performance levels. See Section II of Appendix C for additional detail on the calculation of performance rates and required active demand resources for the sub-regions in southern New England.

Exhibit 7-7
Estimated Active Demand Resources Required for Combination NTA

Scenario	Year	Total Gap	Required Resources Based on FCA #5 Performance Factors		Required Resources Based on FCA #6 Performance Factors	
			Average Performance Rate	Resources Required to Fill Gap	Average Performance Rate	Resources Required to Fill Gap
		MW	%	MW	%	MW
Reference DR Case	2015	2,075	60%	3,482	73%	2,835
	2020	3,382	60%	5,568	72%	4,667
Aggressive DR Case	2015	2,011	59%	3,381	73%	2,754
	2020	2,937	59%	4,871	73%	4,083

As mentioned, active demand resources do not provide a one MW load reduction for every one MW installed. A specific forecast for active demand resources was not generated as part of this analysis. However, to estimate the additional quantity of active demand resources that would be required to satisfy the identified gap (up to 3,382 MW of load reduction in 2020) historical performance of active demand response resources was used to determine an appropriate derate. Given the range of performance estimates available, a range of results are shown to provide a reasonable expectation for the quantity of active demand response required. Further, the load reduction requirement itself reflects a floor to the active resource requirement which would be considered a very conservative measure of the incremental resources required. The conservative nature of this estimate is even greater given that it does not consider resource fatigue due to the increased frequency at which the active demand resources would be called on to perform as the reliance on these resources increases.

Overall, to achieve the CLL in the Combination NTA Cases, the total required incremental active demand resource which would be required are a minimum of 2,011 MW in 2015 and 2,397 MW in 2020, assuming the active demand resource capacity is not derated to account for the performance rate. The highest level of resources estimated is 3,482 MW in 2015 to 5,568 MW in 2020.

As shown in Exhibit 7-8, 1,102 MW of Active Demand Response Resources qualified and remained listed in FCA #5. This means that to satisfy the reliability criteria in 2015 the resources shown to be available in the current year forward capacity auctions would need to more than double in a single year in the best case, and in the worst case would need to increase by 4.2 times. To satisfy reliability criteria in 2020, an annual average growth rate of between 26 percent and 35 percent in active demand resources would be required. Expanding these results to all of New England and assuming a 0.7 percent annual average growth rate in the New England capacity requirement, this would imply that active and passive demand resources represent between 23 and 28 percent of the capacity requirement by 2020 versus the current share of roughly percent.

Exhibit 7-8
Active Demand Resources Required to Provide an NTA in the Combination Case assuming Reference Passive DR Case

Parameter	Combination NTA 2015			Combination NTA 2020		
	No Derate	FCA #5 Derate	FCA #6 Proposed Derate	No Derate	FCA #5 Derate	FCA #6 Proposed Derate
FCA 5 (2014/15) Qualified Active Demand Response Resources (MW)[1]	1,102					
Incremental Active Demand Resource Required to Eliminate Thermal Violations in the Combination Case (MW)	2,075	3,482	2,835	3,382	5,568	4,667
Total (cumulative) Demand Resource Required (MW)	3,177	4,584	3,937	4,484	6,670	5,769
Average Annual Percentage Growth (%)	188%	316%	257%	26%	35%	32%

1) The qualified resources from FCA #5 are used as a proxy for the total available demand response resources available for the summer of 2014 as of today. Total is shown for the Rhode Island, Connecticut, and Massachusetts load zones only as the area of concern. The total qualified Real Time Demand Response Resource for all of New England is 1,667 MW. Within Rhode Island, Connecticut, and Massachusetts load zones, 1,207 MW of capacity qualified. Of this total, 105 MW were accepted for delist, resulting in qualified Real Time Demand Response Resources of 1,102 MW in southern New England.

As shown in Exhibit 7-9, even when considering the Aggressive DR Case, the growth in Active Demand Response Resources would still be overwhelming at between 24 and 33 percent average growth rate through 2020.

Exhibit 7-9
Active Demand Resources Required to Provide an NTA in the Combination Case assuming Aggressive Passive DR Case

Parameter	Combination NTA 2015			Combination NTA 2020		
	No Derate	FCA #5 Derate	FCA #6 Proposed Derate	No Derate	FCA #5 Derate	FCA #6 Proposed Derate
FCA 5 (2014/15) Qualified Active Demand Response Resources (MW)[1]	1,102					
Incremental Active Demand Resource Required to Eliminate Thermal Violations in the Combination Case (MW)	2,011	3,381	2,754	2,937	4,871	4,083
Total (cumulative) Demand Resource Required (MW)	3,113	4,483	3,856	4,039	5,973	5,185
Average Annual Percentage Growth (%)	182%	307%	250%	24%	33%	29%

1) The qualified resources from FCA #5 are used as a proxy for the total available demand response resources available for the summer of 2014 as of today. Total is shown for the RI, CT, and MA load zones only as the area of concern. The total qualified Real Time Demand Response Resource for all of New England is 1,667 MW. Within RI, CT and MA load zones, 1,207 MW of capacity qualified. Of this total, 105 MW were accepted for delist, resulting in qualified Real Time Demand Response Resources of 1,102 MW in southern New England.

7.3 Sensitivity Scenarios

ICF modeled and analyzed two sensitivity scenarios to assess the impact of potential changes in the New England market on the results of the Combination NTA assessments. The sensitivity scenarios were:

- **Salem Harbor Retirement Sensitivity** – In this sensitivity, the Salem Harbor generation plant is assumed to retire in 2014. Recently, the owner of the Salem Harbor generators has indicated its intention to retire the Salem Harbor units by summer, 2014 and ISO-NE has directed Transmission Owners to assume that Salem Harbor is out of service in all needs analyses of the system from 2014 forward. Therefore, ICF analyzed a sensitivity scenario in which the Salem Harbor power plant was retired.
- **Northern New England Generation Injection Sensitivity** – In this scenario ICF assumed that up to 1,400 MW of incremental generation capacity will be available from new generation facilities in northern New England by 2015. ICF modeled an incremental 1,400 MW of generation at the Tewksbury substation as a proxy for generation available from northern New England.

Since the Salem generation facility and the Tewksbury proxy generation injection are both located in Eastern NE, ICF determined that the two sensitivity scenarios would affect the analysis of load serving capability in only Eastern NE. Specifically, dispatch conditions in the two sensitivities relative to the Needs Assessment dispatch scenarios would change only in Eastern NE. Generation dispatch conditions in Rhode Island and Western NE would remain the same in the sensitivity scenarios. However, dispatch conditions in Eastern NE would change in each sensitivity scenario relative to the Needs Assessment cases. Therefore the sensitivity analyses were conducted only for Eastern NE.

Further, since an NTA solution was not found for any NTA cases, ICF used the Aggressive DR Combination NTA, the most optimistic of the NTA cases, as the basis for the sensitivity analyses. To develop the Aggressive DR Combination NTA 401 MW of new generation and 231 MW of passive demand resources were added in Eastern NE in 2015. In 2020 an additional 879 MW of passive demand resources were added in Eastern NE for a total of 1,110 MW. The generation represented all available generation in Eastern NE in the Interconnection Queue. The resources were in addition to new generation and passive demand resources in Western NE and Rhode Island. As noted, the base power flow cases included all generation and passive and active demand resources that cleared in FCA #4.

Exhibit 7-10 provides a summary of the results for the Salem Harbor Retirement Sensitivity (see Section IV of Appendix B for list of overloaded transmission facilities).

Exhibit 7-10
Summary of Reliability Criteria Violations for Salem Harbor Retirement Sensitivity

Year	Number of Thermal Violations			Number of Elements Overloaded		
	Combination NTA[1]	Sensitivity Scenario	Percent Reduction	Combination NTA[1]	Sensitivity Scenario	Percent Reduction
2015	56	70	-25%	12	13	-8%
2020	72	88	-22%	15	15	0%

[1] Number of violations in Eastern NE only.

Exhibit 7-11 provides a summary of the results for the Northern New England Generation Injection Sensitivity (see Section V of Appendix B for list of overloaded transmission facilities).

Exhibit 7-11
Summary of Reliability Criteria Violations for Northern New England Generation Injection Sensitivity

Year	Number of Thermal Violations			Number of Elements Overloaded		
	Combination NTA[1]	Sensitivity Scenario	Percent Reduction	Combination NTA[1]	Sensitivity Scenario	Percent Reduction
2015	56	3	95%	12	2	83%
2020	72	2	97%	15	1	93%

[1] Number of violations in Eastern NE only.

7.4 Conclusions

Considered separately, neither generation resources nor demand resources are available in sufficient quantities to develop NTA solutions that would resolve all the violations that Interstate addresses. To determine if combinations of demand and supply resources could resolve all the violations, ICF developed two NTAs from combinations of generation resources and passive demand resources. The first, the Reference DR Combination NTA, used ICF's estimate of passive demand resources in the Reference DR Case. The second, the Aggressive DR Combination NTA, used ICF's estimate of passive demand resources in the Aggressive DR Case. The passive demand resources in both the Reference DR Case and the Aggressive DR Case were incremental to the amounts that cleared in FCA #4.

ICF's analyses showed that neither of the combination NTAs could resolve all the identified reliability criteria violations. ICF then determined the gap in resources required to produce an NTA solution and found that potentially available active demand resources could not fill the gap. Therefore ICF's analyses show that potentially available generation resources and active and passive demand resources are not sufficient to develop a feasible combination NTA solution.

Further, ICF analyzed two sensitivity scenarios. In the first, the Salem Harbor generators were allowed to retire. ISO-NE has directed Transmission Owners to assume that the Salem Harbor generators will be out of service in all needs analyses of the system from 2014 forward because the owner has indicated its intention to retire the units by summer, 2014. Reliability criteria violations worsened under this sensitivity scenario.

In the second sensitivity scenario ICF assumed that up to 1,400 MW of incremental generation capacity will be available from new generation facilities in northern New England by 2015. This improved the situation, but could not resolve all of the violations.

A separate analysis of the New England system with Interstate in place showed that Interstate resolves all the identified reliability criteria violations, even under the sensitivity scenarios.

APPENDIX A
Description of Needs Assessment Power Flow Cases and Dispatch Conditions

The table in Exhibit A-1 describes the 8 base power flow cases ICF used in performing the load serving capability assessment for Eastern NE, Western NE and Rhode Island. ISO-NE developed the power flow cases for the updated needs assessment study for the Interstate Reliability Project. The table shows some of the key assumptions for each power flow case, including demand conditions, generation resources or supply sources considered out-of-service (OOS), and interface flow assumptions. Each base case was subjected to contingencies defined by NERC, NPCC and ISO standards and criteria, including the loss of a transmission circuit, transformer, or bus section and also the loss of multiple elements that might result from a single event such as a circuit breaker failure or loss of two circuits on a multiple-circuit tower. The loss of a single transmission element is referred to as an N-1 contingency. The loss of a single transmission component followed by the loss of a second component is referred to as an N-1-1 contingency.

ICF used at least two power flow cases for the Eastern NE and Rhode Island load serving capability analyses, one representing summer peak load conditions in 2015 and the other representing similar conditions in 2020. For the Western NE load serving capability analysis, ICF used two power flow cases in each study year, one for N-1 and the second for N-1-1 analysis. The reason for using a greater number of cases for the Western NE analysis is that New England can export power to New York across the Cross Sound Cable and the Norwalk-Northport Cable under N-1 conditions, but not under N-1-1 conditions. These power exports from the western parts of southern New England to New York can affect load serving capability in Western NE, but have no effect on load serving capability in RI or Eastern NE. Therefore, for testing Western NE load serving capability, a power flow case simulating exports to New York was used for the N-1 analysis, and a second case with curtailed exports to New York was used for the N-1-1 analysis.

Further, dispatch conditions were created to stress each of the areas of interest. In each case the two largest generating units or supply sources in the sub-regions of interest were assumed to be out of service.

- New England West to East: The Hydro Quebec Phase II HVDC line and the Seabrook generating station were assumed to be out of service.
- New England East to West: Millstone Units 2 and 3 were assumed to be out of service. In addition the Berkshire Power plant was modeled offline to represent forced outage in the area of interest.
- Rhode Island Reliability: The RISEP generating station and the Manchester 09 combined cycle plant were assumed to be out of service.
- Connecticut Reliability: Same as New England East to West

Exhibit A-1 REDACTED TO PROTECT CEII
Description of Needs Assessment Power Flow Cases

Case #	Purpose	Case Description				
		Year	Load Assumption	Primary Resource Assumptions	Interface Flow Assumption	Contingency Analysis
1	Load Serving Capability in RI	2015	90/10 Summer Peak	[redacted]	-	N-1/N-1-1
2		2020	90/10 Summer Peak	[redacted]	-	N-1/N-1-1
3	Load Serving Capability in Western NE	2015	90/10 Summer Peak	[redacted]	LI Exports (CSC+Norwalk Cables) at 450 MW	N-1
4		2015	90/10 Summer Peak	[redacted]	LI Exports (CSC+Norwalk Cables) at 0 MW	N-1-1
5		2020	90/10 Summer Peak	[redacted]	LI Exports (CSC+Norwalk Cables) at 450 MW	N-1
6		2020	90/10 Summer Peak	[redacted]	LI Exports (CSC+Norwalk Cables) at 0 MW	N-1-1
7	Load Serving Capability in Eastern NE	2015	90/10 Summer Peak	[redacted]	NE-NB at 0 MW	N-1/N-1-1
8		2020	90/10 Summer Peak	[redacted]	NE-NB at 0 MW	N-1/N-1-1

APPENDIX B
Detailed Power Flow Results

Appendix B provides the detailed results of ICF's power flow simulations. Since this information provides details about the transmission of energy that, together with other information provided in this report, could be useful to a person in planning an attack on critical infrastructure, it qualifies as Critical Energy Infrastructure Information (CEII) under guidelines issued by the Federal Energy Regulatory Commission, which require ICF and its clients to limit dissemination of the information. Accordingly, this information will be provided to the state regulatory agencies with jurisdiction over the Interstate Reliability Project, and provided to participants in proceedings before such agencies, in accordance with each agency's regulations or procedures adopted to protect CEII. This information may also be provided to qualified recipients outside of the context of such proceedings pursuant to each company's CEII policies and procedures.

Persons who wish to receive a complete copy of this report; believe they may be qualified to receive CEII and; who are willing to sign an appropriate Confidentiality Agreement limiting use of CEII should contact:

Contact Information
Robert E. Carberry Project Manager NEEWS Siting and Permitting Northeast Utilities Service Company Post Office Box 270 Hartford, CT 06141-0279
Glenda Jones National Grid 40 Sylvan Road Waltham, MA 02451
Judah Rose Managing Director ICF International 9300 Lee Highway Fairfax, VA 22031

APPENDIX C
Incremental Active Demand Resource Capacity Projections

I. Historical Performance of Active Demand Resources

Exhibit C-1 presents the historical performance of active demand resources in southern New England as applied in the assumptions for FCA #5. For long-term transmission planning purposes, Real Time Emergency Generation (RTEG) is not considered as an alternative to transmission given that it is used as an operational measure to respond in stress conditions. Hence, RTEG is considered for operational purposes rather than planning purposes. In the ICF analysis, RTEG resources are not considered to be included as a type of active resource available to meet the additional load reduction requirement.

Exhibit C-1
Historical Performance of Active Demand Resources in Southern New England – FCA #5

	Real Time Demand Response		Real Time Emergency Generation		Total Active Resource	
Load Zone	Summer MW	Performance (%)	Summer MW	Performance (%)	Summer MW	Performance (%)
CT	370.481	76	300.301	87	670.782	81
RI	74.931	48	98.478	17	173.409	30
SEMA	165.573	56	78.637	58	244.210	57
WCMA	169.213	67	101.193	72	270.406	69
NEMA/Boston	285.866	72	143.624	87	429.490	77

Source: Installed Capacity Requirement (ICR) and Related Values for the 2014/15 Forward Capacity Auction (FCA #5), ISO-NE.

As shown, the real-time demand response has performed at relatively low levels in the southern New England market areas. The performance rates directly affect the ability of the active demand resources to reduce the load. For example, in Rhode Island, the real time demand response has performed at less than 50 percent, indicating that roughly 2 MW of active demand resource are required for every 1 MW of load reduction needed.

In FCA #6, ISO-NE has proposed a change to the methodology used to estimate the performance factors for demand resources. ISO-NE will consider performance in the latest year available of the resources cleared in the FCM auction for that capacity period. This method reflects use of actual data for FCM resources during the 2010 capacity year – the first historical FCM period available. Exhibit C-2 shows the performance of active demand resources in southern New England as applied in the assumptions for FCA #6.

Exhibit C-2
Historical Performance of Active Demand Resources in Southern New England – FCA #6

	Real Time Demand Response		Real Time Emergency Generation		Total Active Resource	
Load Zone	Summer MW	Performance (%)	Summer MW	Performance (%)	Summer MW	Performance (%)
CT	272.779	75	203.474	67	476.253	72
RI	49.418	100	79.956	56	129.374	73
SEMA	149.659	64	72.458	59	222.117	62
WCMA	133.643	100	88.855	49	222.498	80
NEMA/Boston	241.438	68	132.210	60	373.648	65

Source: Assumptions for the Installed Capacity Requirement (ICR) for the 2015/16 Forward Capacity Auction (FCA6), August 25, 2011, ISO-NE.

II. Required Active Demand Resources for Demand NTA

The performance factor derates the capacity of the demand resource when determining the demand resource capacity for the required load reduction. Exhibit C-3 shows the performance rates and required active demand resources in each of the three sub-regions and also in southern New England for the Reference DR Case. This is based on the performance level assumptions used in FCA #5.

Exhibit C-3
Estimated Active Demand Resources Required – FCA #5

	2015			2020		
	Total Gap	Average Performance Rate	Required Resources to fill Gap	Total Gap	Average Performance Rate	Required Resources to fill Gap
	MW	%	MW	MW	MW	MW
Rhode Island	753	48%	1,568	939	48%	1,955
Western New England	214	73%	293	920	73%	1,259
Eastern New England	2,092	65%	3,809	2,003	65%	3,072
Southern New England	3,058	67%	5,070	3,861	67%	6,287

NOTES: Western New England performance rate is the weighted average of Connecticut and WCMA. Eastern New England is the weighted average of SEMA and NEMA/Boston.

The performance rates and required load reduction in the Reference DR Case, assuming FCA #6 demand resource performance levels, is shown in Exhibit C-4.

Exhibit C-4
Estimated Active Demand Resources Required – FCA #6

	2015				2020		
	Total Gap	Average Performance Rate	Required Resources to fill Gap		Total Gap	Average Performance Rate	Required Resources to fill Gap
	MW	%	MW		MW	MW	MW
Rhode Island	753	100%	753		939	100%	939
Western New England	214	83%	257		920	83%	1105
Eastern New England	2,092	66%	3,147		2,003	66%	3,013
Southern New England	3,058	74%	4,157		3,861	76%	5,058

NOTES: Western New England performance rate is the weighted average of Connecticut and WCMA. Eastern New England is the weighted average of SEMA and NEMA/Boston.

The performance rates and required load reduction in the Aggressive DR Case are shown in Exhibits C-5 and C-6, using demand resource performance level assumptions in FCA #5 and FCA #6, respectively.

Exhibit C-5
Estimated Active Demand Resources Required – FCA #5

	2015				2020		
	Total Gap	Average Performance Rate	Required Resources to fill Gap		Total Gap	Average Performance Rate	Required Resources to fill Gap
	MW	%	MW		MW	MW	MW
Rhode Island	739	48%	1,540		865	48%	939
Western New England	187	73%	256		762	73%	1105
Eastern New England	2,069	65%	3,183		1,790	65%	3,013
Southern New England	2,995	60%	4,979		3,417	61%	5,603

NOTES: Western New England performance rate is the weighted average of Connecticut and WCMA. Eastern New England is the weighted average of SEMA and NEMA/Boston.

Exhibit C-6
Estimated Active Demand Resources Required – FCA #6

	2015			2020		
	Total Gap	Average Performance Rate	Required Resources to fill Gap	Total Gap	Average Performance Rate	Required Resources to fill Gap
	MW	%	MW	MW	MW	MW
Rhode Island	739	100%	739	865	100%	865
Western New England	187	83%	225	762	83%	918
Eastern New England	2,069	66%	3,135	1,790	66%	2,712
Southern New England	2,995	73%	4,099	3,417	76%	4,495

NOTES: Western New England performance rate is the weighted average of Connecticut and WCMA. Eastern New England is the weighted average of SEMA and NEMA/Boston.

III. Required Active Demand Resources for Combination NTA

Exhibits C-7 and C-8 present the active demand resources required to produce an NTA solution from the Combination NTA using performance rates based on FCA #5 and FCA #6, respectively. These results are based on the Reference DR Case. The estimates for the Combination NTA based on the Aggressive DR Case are shown in Exhibits C-9 and C-10.

Exhibit C-7
Estimated Active Demand Resources Required – FCA #5

	2015			2020		
	Total Gap	Average Performance Rate	Required Resources to fill Gap	Total Gap	Average Performance Rate	Required Resources to fill Gap
	MW	%	MW	MW	MW	MW
Rhode Island	553	48%	1,152	739	48%	1,540
Western New England	27	73%	37	158	73%	216
Eastern New England	1,495	65%	2,293	2,485	65%	3,812
Southern New England	2,075	60%	3,482	3,382	60%	5,568

NOTES: Western New England performance rate is the weighted average of Connecticut and WCMA. Eastern New England is the weighted average of SEMA and NEMA/Boston. Values shown at load bus level.

Exhibit C-8
Estimated Active Demand Resources Required – FCA #6

	2015			2020		
	Total Gap	Average Performance Rate	Required Resources to fill Gap	Total Gap	Average Performance Rate	Required Resources to fill Gap
	MW	%	MW	MW	MW	MW
Rhode Island	553	100%	553	739	100%	739
Western New England	27	83%	32	158	83%	190
Eastern New England	1,495	66%	2,249	2,485	66%	3,739
Southern New England	2,075	73%	2,835	3,382	72%	4,667

NOTES: Western New England performance rate is the weighted average of Connecticut and WCMA. Eastern New England is the weighted average of SEMA and NEMA/Boston. Values shown at load bus level.

Exhibit C-9
Estimated Active Demand Resources Required – FCA #5

	2015			2020		
	Total Gap	Average Performance Rate	Required Resources to fill Gap	Total Gap	Average Performance Rate	Required Resources to fill Gap
	MW	%	MW	MW	MW	MW
Rhode Island	48%	1,123	665	48%	1,385	48%
Western New England	73%	-	-	73%	-	73%
Eastern New England	65%	2,258	2,272	65%	3,485	65%
Southern New England	59%	3,381	2,937	59%	4,871	59%

NOTES: Western New England performance rate is the weighted average of Connecticut and WCMA. Eastern New England is the weighted average of SEMA and NEMA/Boston. Values shown at load bus level.

Exhibit C-10
Estimated Active Demand Resources Required – FCA #6

	2015			2020		
	Total Gap	Average Performance Rate	Required Resources to fill Gap	Total Gap	Average Performance Rate	Required Resources to fill Gap
	MW	%	MW	MW	MW	MW
Rhode Island	539	100%	539	665	100%	665
Western New England	-	83%	-	-	83%	-
Eastern New England	1,472	66%	2,215	2,272	66%	3,418
Southern New England	2,011	73%	2,754	2,937	73%	4,083

NOTES: Western New England performance rate is the weighted average of Connecticut and WCMA. Eastern New England is the weighted average of SEMA and NEMA/Boston. Values shown at load bus level.

APPENDIX D
Summary of Resources Selected from the Generation Interconnection Queue

Exhibit D-1
Rhode Island – Category 2 (Generators with 1.3.9 Approval)

Queue Position	Requisition Date	Unit Name	Unit	Fuel	County	State	Interconnection Point
342	7/21/2010	Exciter Upgrades & increase	CC	NG	Providence	RI	NGRID 115 kV Franklin substation
243	1/4/2008	Increase to Steam Turbine Capacity Uprate (See QP #231)	ST	BIT	Bristol	MA	Brayton Point 345 kV Switchyard
262	5/23/2008	Rhode Island Landfill Gas Genco Increase (see QP #233)	CC	LFG	Providence	RI	NGRID 115 kV S171 line

Exhibit D-2
Rhode Island – Category 3 (All Other Generators)

Queue Position	Requisition Date	Unit Name	Unit	Fuel	County	State	Interconnection Point
332	5/13/2010	Combined Cycle increase	CC	NG	Providence	RI	115 kV RISE substation
325	2/10/2010	Wind	WT	WND	Washington	RI	GRID Brayton Point 345 kV substation
308	8/28/2009	Wind	WT	WND	Washington	RI	NGRID 3302 Feeder

Exhibit D-3
Western NE – Category 1 (Generators with Interconnection Agreement)

Queue Position	Requisition Date	Unit Name	Unit	Fuel	County	State	Interconnection Point
269	7/14/2008	Indian River Power	HD	WAT	Hampden	MA	WMELCO 23 kV circuit
108	5/12/2003	Hoosac Wind Project	WT	WND	Berkshire & Franklin	MA	Line Y25S
135	8/19/2005	Russell Biomass	ST	WDS	Hampden	MA	Blanford - Southwick - Elm 115 kV line
196	1/16/2007	Northfield Mt Upgrade #3	PS	WAT	Franklin	MA	W. Mass Northfield 345 kV substation
196	1/16/2007	Northfield Mt. Upgrade #2	PS	WAT	Franklin	MA	W. Mass Northfield 345 kV substation
196	1/16/2007	Northfield Mt. Upgrade #4	PS	WAT	Franklin	MA	W. Mass Northfield 345 kV substation
196	1/16/2007	Northfield Mt Upgrade #1	PS	WAT	Franklin	MA	W. Mass Northfield 345 kV substation

Exhibit D-4
Western NE – Category 2 (Generators with 1.3.9 Approval)

Queue Position	Requisition Date	Unit Name	Unit	Fuel	County	State	Interconnection Point
222	7/16/2007	Combined Cycle	CC	NG	New Haven	CT	Haddam Neck-Southington 345 kV line
236	11/30/2007	Combined Cycle	CC	NG	Hampden	MA	115 kV line between Buck Pond and Pochassic substations-1302 line
174	10/13/2006	Combined Cycle	CC	NG	Hampden	MA	345 kV Stony Brook Substation
328	5/6/2010	Wind	WT	WND	Worchester	MA	GRID 69 kV S19 at E. Webster Substation
328	5/6/2010	Wind	WT	WND	Worchester	MA	GRID 69 kV S19 at E. Webster Substation
250	2/13/2008	Gas Turbine	GT	NG	Hartford	CT	CL&P Windsor Locks Substation
289	1/8/2009	Fuel Cell	FC	NG	New Haven	CT	UI's Milvon substation
289	1/8/2009	Combustion Turbine	GT	NG	Fairfield	CT	UI's Trap Falls substation
241	12/31/2007	Towantic Energy increase	CC	NG	New Haven	CT	CL&P 115 kV lines between Baldwin Junction and Beacon Falls
273	8/3/2008	Biomass Project	ST	WDS	Hampden	MA	115 kV line near E. Springfield substation

Exhibit D-5
Western NE – Category 3 (All Other Generators)

Queue Position	Requisition Date	Unit Name	Unit	Fuel	County	State	Interconnection Point
319	12/14/2009	Power Station Increase	ST	NUC	New London	CT	CL&P Millstone 345 kV substation
320	12/15/2009	Combined Cycle	CC	NG	Fairfield	CT	Norwalk Harbor 115 kV station
359	3/7/2011	AVR Replacement/PSS	PS	WAT	Franklin and Bershire	MA	Bear Swamp 230 kV substation
359	3/7/2011	AVR replacement/PSS	PS	WAT	Franklin and Berkshire	MA	GRID Bear Swamp 230 kV substation
344	9/7/2010	Combined Cycle Increase	CC	NG	Hampden	MA	NU 115 kV Shawanigan
356	2/4/2011	Combined Cycle increase	CC	NG	Berkshire	MA	WMECO Doreen 19A substation
282	10/15/2008	Biomass Project	ST	WDS	Franklin	MA	115 kV line near Montage or Fench King substations
315	10/20/2009	Hydro Uprate	HD	WAT	Hampden	MA	WMECO 19J1 23 kV line
360	3/14/2011	Hydro	HD	WAT	Hampden	MA	WMECO 23 kV circuit
254.5	3/25/2008	Wind Project	WT	WND	Berkshire	MA	WMECO Berkshire substation 23 kV circuit
360	3/14/2011	Hydro	HD	WAT	Franklin	MA	WMECO 13.8 kV
306	7/13/2009	Overflow #3	HD	WAT	Hampden	MA	HG&E Holyoke Substation

Exhibit D-6
Eastern NE – Category 1 (Generators with Interconnection Agreement)

Queue Position	Requisition Date	Unit Name	Unit	Fuel	County	State	Interconnection Point
178	11/2/2006	Brockton Combined Cycle	CC	NG	Plymouth	MA	115 kV F19 and E20 lines

Exhibit D-7
Eastern NE – Category 2 (Generators with 1.3.9 Approval)

Queue Position	Requisition Date	Unit Name	Unit	Fuel	County	State	Interconnection Point
296	3/20/2009	Exciter Replacement	ST	BIT	Essex	MA	Salem Switchyard
89	6/6/2001	Cape Wind Turbine Generators	WT	WND	N/A	MA	Near Barnstable 115 kV Substation

Exhibit D-8
Eastern NE – Category 3 (All Other Generators)

Queue Position	Requisition Date	Unit Name	Unit	Fuel	County	State	Interconnection Point
352	12/14/2010	Increase (Q296)	ST	BIT	Essex	MA	Salem Switchyard
331	5/13/2010	Combined Cycle increase	ST	NG	Middlesex	MA	115 kV Line 875-539 to NSTAR 875 substation
353	12/21/2010	Wind	WT	WND	Barnstable	MA	NSTAR 115 kV Valley substation
353	12/21/2010	Wind	WT	WND	Plymouth	MA	NSTAR 115 kV Valley substation
343	8/10/2010	Operating change	ST	NUC	Plymouth	MA	NSTAR 342 & 355 Line/345 switchyard

APPENDIX E
Non-Transmission Resources Capital Cost Assessment Methodology

I. Introduction

This appendix describes the approach used to estimate the installation or implementation cost of selected NTA options analyzed in ICF's study. As discussed in the report, ICF did not find a feasible NTA solution, therefore in this appendix ICF calculates the cost of a hypothetical NTA solution based on the Combination NTA Cases described in Chapter 7. Because the Combination NTAs did not produce an NTA solution, ICF assumes that active demand resources in the form of interruptible load will be used to bridge the gap and produce an NTA that resolves all the identified violations. The Combination NTAs are used in this exercise because ICF believes they are the most conservative in terms of NTA cost. The cost calculations are meant to be indicative of the capital cost required to implement an NTA solution, relative to the capital cost of the Interstate project, which is currently estimated at $532 million. Where appropriate, ICF makes conservative assumptions regarding the supply side resource mix and unit costs. Although implementing either Interstate or an NTA solution will provide economic benefits to the New England market, the assessment of quantitative benefits of the Interstate Project and the NTA solutions is outside the scope of this study, and is not included in the discussion in this appendix.

The unit cost estimates of supply side and demand side resources are based on data from the companies (Northeast Utilities and National Grid), public sources, and ICF's internal assumptions.

I.1 Supply Side Resources

ICF used generic capital cost information from public sources, and confirmed that these assumptions are reasonable by referring to available information for existing or planned generation units in the New England market. This information accounts for environmental regulations in New England, which could require new gas-fired power plants to utilize air cooling technology as opposed to much less costly water cooling. ICF also included interconnection and network upgrade costs.

I.2 Demand Side Resources

Providing capital cost estimates for demand side resources is more challenging than that for supply side resources for several reasons. First, there are several different categories of demand resources, each with a different cost profile. Second, the incremental cost of new demand resources increases significantly as more capacity is required. Third, the cost of demand resources depends on the performance characteristics required. Fourth, the performance of demand side resources, especially interruptible loads under challenging circumstances has not yet been tested. Specifically, a period of prolonged calls for interruption, (for example, 60 hours per year, or more than 100 hours per year), has not been experienced. This is important because the recent large increase in the reliance on demand side resources in

ISO-NE and elsewhere has not been exposed to high demand levels, in part due to the recent recession.[52]

ICF first estimated the cost of potentially achievable passive demand resources used in the Reference DR Case and the Aggressive DR Case in developing Combination NTAs described in Chapter 7. The cost of passive demand resources is based on funding from the state DSM programs.[53] Next, ICF determined the cost of active demand resources required to supplement the resources in the Combination NTA and produce an NTA solution. This is based on the assumption that some customers will opt to be compensated in exchange for a reduction in demand or outright curtailment during emergencies. The cost of such programs depends on the number of hours of curtailment expected each year, the amount of energy curtailed and the cost to customers of losing supply of electricity. ICF estimated an average number of hours of curtailment per customer and the amount of energy curtailed based on the results of its CLL duration analysis. The cost per unit of demand curtailed was based on estimates of the Value of Lost Load (VoLL).

II. Supply Side Resource Cost

ICF used generic cost estimates for combined cycle facilities as representative of supply side resources that will be used for NTAs in southern New England. Of the 2,850 MW of southern New England supply side resources available in the ISO-NE Interconnection Queue and used in ICF's NTA assessment, approximately 85 percent is combined cycle capacity. This is similar to the recent historical trend in New England. Nearly all of the capacity added in ISO-NE over the past 15 years has been natural gas-fired combined cycle capacity. In contrast, there has been very little peaking capacity such as simple cycle combustion turbines. This preponderance of combined cycles is due to the view that the greater profits in the energy market offset the higher capital costs relative to simple cycle combustion turbines. This is in turn due to the greater thermal efficiencies of combined cycles. Also, the lower emissions are attractive aspects of combined cycles. In general, none of the other technologies have been close in terms of market acceptance in ISO-NE in the absence of subsidies such as RECs, and PTCs. Also, the addition of new variable renewable resources may require much more installed capacity to achieve the same peak hour output as a combined cycle plant – e.g., storage or more capacity.

Exhibit E-1 shows generic cost information for natural gas-fired combined cycle resources from a recent U.S. Energy Information Administration (EIA) study.[54] The study included the costs of a generic 540 MW conventional natural gas combined cycle facility and a generic 400 MW

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[52] *In this regard, the PJM Interconnection (PJM) has taken steps, with FERC approval, to limit the amount of interruptible demand resources. Interruptible load that can only be interrupted 60 hours a year (ten times of 6 hours each) is limited to 4.7% of peak. The most recent PJM Reliability Pricing Model found almost no DSM willing to be exposed to unlimited amounts of interruption either in the summer or annually. PJM target for Limited DR was 4.7% of peak. In the most recent PJM capacity auction, the amount of cleared Limited DR reached to 7.3% of total peak. This is because the total amount was close to 20% of peak, and the excess over peak was largely filled by this resource (PJM has a downward sloping capacity demand curve).*

[53] *ISO NE divides demand side resources into two types of passive energy efficiency resources, interruptible load and emergency generation. In the most recent FCA, most of the active resources were interruptible. As noted, the amount of emergency generation is limited.*

[54] *Updated Capital Cost Estimates for Electricity Generation Plants, November 2010, U.S. Energy Information Administration.*

advanced natural gas combined cycle facility. It also accounted for regional differences in facility costs.

The capital costs shown in Exhibit E-1 are consistent with ICF's internal views about generic combined cycles and also consistent with ICF's internal views about the large regional cost premium for plants in ISO-NE relative to the US average cost. From the results of the study, the overnight capital costs to develop combined cycle facilities in Connecticut, Massachusetts and Rhode Island are between $1,195/kW and $1,396/kW in 2010$. The state with the highest costs is Massachusetts, and the one with the lowest is Rhode Island. Capital costs are slightly higher for the advanced combined cycle (H class) versus conventional (F Class). Thus, as shown, a 540 MW conventional technology combined cycle in Connecticut would cost $677 million (540MW * $1,254/kW * 1000kW/MW) on an overnight basis (i.e., without Interest During Construction or IDC) and without the necessary interconnections.

Exhibit E-1
Overnight Capital Cost of New Combined Cycle Generators

Technology	Capacity (MW)	Overnight Capital Cost (2010$/kW)[1]		
		CT	MA	RI
Conventional natural gas combined cycle	540	1,254	1,372	1,195
Advanced natural gas combined cycle	400	1,278	1,396	1,220

[1] Excludes IDC, electric transmission upgrades and firm gas transmission cost.

Exhibit E-2 shows the cost of the combined cycle facilities adjusted to include IDC, electric transmission upgrade cost and firm gas transmission cost. ICF assumes IDC of $93/kW, electric transmission upgrade cost of $40/kW and firm gas transmission cost of $100/kW.[55]

Exhibit E-2
Overnight All-Inclusive Capital Cost of New Combined Cycle Generators

Technology	Capacity (MW)	Overnight Capital Cost (2010$/kW)[1]		
		CT	MA	RI
Conventional natural gas combined cycle	540	1,487	1,605	1,428
Advanced natural gas combined cycle	400	1,511	1,629	1,453

[1] Includes IDC of $93/kW, electric transmission upgrade cost of $40/kW and firm gas transmission cost of $100/kW.

The actual costs would be escalated with general inflation. At an inflation rate of 2.5 percent per year, the overnight cost of a 540 MW combined cycle in Connecticut would be $867 million (in nominal dollars). IDC, electric transmission upgrade cost, and firm gas transmission cost would

[55] *Firm gas transmission cost is included because of the high level of reliability expected of these plants.*

increase this amount to $1.028 billion (in nominal dollars). The cost could be as high as $3.41 billion (in nominal dollars) if a capacity of 1,791 MW is required in 2020.[56]

III. Passive Demand Resource Cost

III.1 Summary of Passive Demand Resource Unit Cost

Exhibit E-3 summarizes the passive demand side resource unit cost used to calculate the cost of Combination NTAs. The unit costs are shown by state for Rhode Island, Massachusetts and Connecticut. The assumptions and approach that form the basis for these unit costs are described below.

Exhibit E-3
Demand Resource Capital Cost

Resource Type	Cost (2010$/kW)
Achievable Passive DR – Massachusetts and Rhode Island	
2015	3,052
2020	3,052
Achievable Passive DR – Connecticut	
2015	2,601
2020	2,689

III.2 Massachusetts and Rhode Island Passive Demand Resource Costs

Massachusetts achievable passive demand resource costs were based on the projected funding and energy savings goals in the Massachusetts Department of Public Utilities Three-Year Energy Efficiency Plan for 2010 through 2012.[57] Exhibit E-4 summarizes the projected funding and energy savings goals for 2010 through 2012.

Exhibit E-4
Derivation of Massachusetts and Rhode Island Passive Demand Resource Cost

Item	2010	2011	2012	2010-2012
Annual Energy Savings Goal (MWh)	624,427	897,232	1,103,423	2,625,083
Summer peak demand (kW)[1]	100,277	145,098	179,139	424,514
Budget ($)	293,828,994	431,251,209	546,821,481	1,271,901,686
Unit Cost ($/kW)	2,930	2,972	3,052	2,996

[1] Assume all utility programs have the same load factor i.e., the same per kWh impact on peak kW demand.

[56] In the combination NTA 1,791 MW of new generation capacity is added in southern New England, composed of 1,569 MW in Connecticut, 999 MW in Massachusetts, and 223 MW in Rhode Island. The cost estimate of $3.41 billion is based on the unit cost in Connecticut, which is intermediate relative to Massachusetts and Rhode Island.)

[57] D.P.U. 09-116 through D.P.U. 09-120, Massachusetts Department of Public Utilities, January 28, 2010.

Between 2010 and 2012 the unit cost of passive demand resource in Massachusetts is expected to increase at the average rate of 2 percent per year from $2,930/kW in 2010 to $3,052/kW in 2012. ICF assumed, conservatively, that after 2012 the unit cost will remain flat at the 2012 level of $3,052/kW for the duration of the NTA assessment. ICF also assumed that passive demand resource costs in Rhode Island will be similar to that in Massachusetts.

III.3 Connecticut Passive Demand Resource Costs

Passive demand resource cost for Connecticut is largely based on projections in the Electric Distribution Companies' Proposed Connecticut Integrated Resource Plan (Connecticut IRP) dated January 1, 2010.[58] As described in Chapter 5, ICF assumed that the energy efficiency available in the Reference DR Case is the energy efficiency achieved through the Reference Level DSM strategy contained in the Connecticut IRP, while the energy efficiency available in the Aggressive DR Case is characterized by the Targeted DSM Expansion resource strategy contained in the Connecticut IRP. The passive demand resource cost is based on the funding for these two programs. The program costs are shown in Exhibit E-5.

Exhibit E-5
Derivation of Connecticut Passive Demand Resource Cost

Parameter		2015	2016	2017	2018	2019	2020
Reference Level DSM	Incremental Achievable Capacity (MW)	37.9	37.2	35.7	35.1	34.5	33.9
	Cost ($/kW)	2,977	3,031	3,139	3,188	3,236	3,285
Targeted DSM Expansion	Incremental Achievable Capacity (MW)	18.4	18.9	18.4	17.8	19.9	19.2
	Cost ($/kW)	1,825	1,827	1,841	1,856	1,807	1,851
Total Incremental Achievable Capacity (MW)		56.3	56.1	54.1	52.9	54.4	53.1
Total Incremental Cost ($MM)		146.4	147.3	145.9	144.9	147.6	146.9
Total Annual Achievable Capacity (MW)		56.3	112.4	166.5	219.4	273.8	326.9
Total Annual Cost ($MM)		146.4	293.7	439.6	584.6	732.2	879.1
Unit Cost of Capacity ($/kW)		2,600	2,613	2,640	2,665	2,674	2,689

The unit cost of demand resource capacity in each year is the ratio of the total annual cost to the total annual achievable capacity. For example, the unit cost of the achievable capacity in 2015 is $2,600/kW (= $146.4 million/(56.3 MW *1000)). In 2020 the unit cost is $2,689/kW (= $879.1 million/(326.9 MW*1000)).

IV. Active Demand Resource Cost

There are two types of active demand resources – Real-Time Emergency Generation (RTEG) and interruptible load. As noted in the report, ISO-NE does not rely on RTEG in system planning. Also, the amount of RTEG accepted in the FCM has been limited to 600 MW. In all

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[58] *Proposed Integrated Resource Plan for Connecticut, Prepared by The Brattle Group, The Connecticut Light and Power Company, and United Illuminating Company, January 1, 2010.*

FCAs today the amount of RTEG that cleared has exceeded the 600 MW limit, and hence the price has been prorated to account for the limited quantity. Thus, we focus on interruptible load, which faces no limit in ISO-NE.

As noted, ISO-NE offers only one type of interruptible load in the FCM, compared to three in PJM.[59] Theoretically, there is the potential that customers will agree to accept interruption of service in exchange for a discount to the cost of service. This is in addition to the savings from not having to pay for the electricity that is not consumed as a result of the interruption. The willingness to accept interruption of would be dependent on the value of the discount just exceeding the expected cost of interruption such as lost production, spoilage, inconvenience, costs of staying at a hotel, etc. This is referred to as the unserved energy costs imposed on the customers or the Value of Lost Load (VoLL).

The main factors used to estimate the cost of the discounts for additional active demand resources are: (1) the Value of Lost Load (VoLL) from industry literature, (2) the number of hours of interruption, and (3) the required load reduction as a fraction of peak load. The number of hours and the reduction in MW of peak load allow for a rough estimation of the energy curtailed. The unserved energy cost (i.e., the VoLL) is estimated based on industry studies summarized by Stoll (1987) with estimates increased to account for inflation. This VoLL was supplemented by an alternative estimate that combines the industry studies and FCM results.

A key reason that we have adopted a methodology which first focuses in on supply and passive demand resources is the great uncertainty regarding active demand resources like interruptible load. This is because there is only limited experience with the current levels of interruptible load, and concerns that this experience results in biased downward estimates of the costs because of the limited use of interruptible load to date. This is also because the requirements for interruptible load associated with the NTAs are far beyond any experienced to date. The requirements are not only for large interruptions, but they are also site-specific interruptions. The need to obtain large reductions from a geographically concentrated area is likely to increase costs relative to a program with more geographic flexibility.

IV.1 FCA #4 Results For Interruptible Power

One source of information on the cost of interruption is the FCM results to date. Exhibit E-6 shows the cost of interruptible power from FCA #4, which was $30/kW-yr in 2013. This represents $27/kW-yr in 2008$ (de-escalated at an annual inflation rate of 2.5%). Using ISO-NE estimate of 50 hours of interruption each year discussed in Appendix F,[60] the corresponding unserved energy cost is $540/MWh ($540/MWh x 50 hrs/year x MW/1,000 kW = $27/kW-yr). In other words, the automatic reduction in consumer bills that is directly due to the decreased usage is not enough to convince consumers not to use the electricity, but rather they have to be paid or given a discount to obtain a binding agreement to accept interruption when demand is above a certain level. Hence this can be thought of the incremental value of the power relative to the price of the electricity. This $540/MWh is much lower than the cost that is used in our analysis for VoLL for reasons discussed below.

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[59] PJM offers three interruptible load products – interruptible load that can be called for up to 60 hours a year, interruptible load that has unlimited calls in a year, and interruptible load that has unlimited calls in the summer.

[60] See Exhibit F-39. The range was 50 to 67 hours per year.

Exhibit E-6
Cost of Interruptible Power from FCA #4

Scenario[1]	FCA 4 Cost ($/kW-yr)	Performance Rate (%)	Hours of Interruption (#)	Implied Incremental Unserved Energy Costs ($/MWh)
1	27[3]	0	50	540 [4]
2	27	61%	50	880
3		50%		1080

[1] Scenarios reflect that uncertainty exists with respect to performance.

[2] If the load saves 15 cents/kWh then the total value is increased by $150/MWh (=(15 cents/kWh)*(1,000 kWh/MWh)*($1/100 cents). However, the payment is just the one needed to supplement the automatic savings from not consuming electricity.

[3] FCA #4 resulted in a $30/kW-yr in Summer 2013, this value has been deescalated to 2008$ assuming 2.5% inflation per year for three years.

[4] $27/kW-yr ÷ 50 hours per year = $540/MWh; 50 hours per year of interruption from ISO-NE estimates.

ISO-NE's FCA #4 resulted in approximately 1,363 MW of cleared interruptible load, of which approximately 971 MW was in southern New England. This was composed of approximately 73 MW of Real-time Demand Response in Rhode Island, approximately 585 MW in Massachusetts, and approximately 312 MW in Connecticut. While the FCA #4 results appear to indicate NTA Real-time Demand Response costs of $540/MWh (both interruption and program cost), this is not likely the correct number to use in our analysis because:

- More Real-time Demand Response is needed, and the lowest cost Real-time Demand Response has already been chosen. Incremental costs therefore should be higher. For example, in southern New England, in the reference DR case, an incremental 3381 MW is required by 2020 for a total of 4352 MW (i.e., 971+3381); this is a 348% increase. Program costs could especially escalate as new equipment (meters, two way control) is needed.

- As noted, Real-time Demand Response has a performance factor of 60 percent to 76 percent on average. Using a performance factor of 61 percent raises the cost from $540/MWh to $880/MWh, or from $27/kW-yr to $44/kW-yr. At a performance factor of 50% (which might be representative) if the hours of interruption increase, the cost rises to $1,080/MWh.

- The CLL analysis assumes that across each zone, load is reduced proportionally, e.g., by 10 percent at all demand nodes. If one relies on the lowest cost load, it may be concentrated at a different location than assumed in the analysis. Because there are no similar restrictions on location in the FCM, the cost may be understated. This problem has led us to consider a range of estimates.

- As noted, FCA #4 contractual provisions are for one year, three years forward. FCA #4 contractual guarantees may not be sufficient to ensure the level of performance needed to avoid violations. For example, a period of 5 to 7 years forward may be needed to provide for the longer lead time of transmission relative to new generation.

- ISO-NE's experience with peak demand response is limited; total demand side resources were 3,349 MW, of which 1363 were real time interruptible load, 1298 MW were passive energy efficiency and 688 were emergency generation resources. This may indicate that the issue of sudden attrition when called frequently (i.e. fatigue) has not been addressed. As noted, PJM has adopted rules in this regard that are more stringent than ISO-NE.

IV.2 Active Demand Resource Duration Analysis

The demand resource duration analysis described in Chapter 5 showed the number of hours demand reduction would be required in each sub-region to ensure load remains below the CLL, assuming no NTA resources were added. The addition of supply side resources and demand resources in the Combination NTA cases reduces both the number of hours and the quantity of required demand reduction. The quantity of demand reduction required to bridge the gap between potentially achievable resources and an NTA solution is discussed in Chapter 7.

For the cost calculation, ICF used an approach similar to the duration analysis to determine the number of hours in each year during which demand reduction from active demand resources will be required to ensure that violations do not occur. This approach is illustrated in Exhibit E-7. The chart represents a load duration curve. The difference between the peak demand and the CLL, shown as *X* MW, is the amount of active demand resources required at the peak. As shown, the duration, or the total number of hours active demand resources will be required during the year is *Y* hours. Some active demand resources will be required for almost all of the hours. Other resources, however, will be required only for a few hours near the peak. If the duration curve is assumed to be triangular, the energy required can be calculated as the areas under the curve, or 0.5**X*Y*.

Exhibit E-8 shows the gap or amount of active demand resource required in each state during the peak, and duration or number of hours in which some demand reduction is required, based on the analysis of the load duration curve for each state.[61] For example, in the Combination NTA with Reference DR Case, approximately 553 MW of demand reduction is required in Rhode Island during the peak period in 2015, and some demand reduction will be required in 221 hours during the year. In 2020 the demand reduction required at peak increases to 739 MW, and the total number of hours increases to 505.

[61] As described in Chapter 5, ICF derived representative 2015 and 2020 load duration curves for each state by scaling the hourly load profile for 2006 using the ratio of the respective year's peak demand to the 2006 peak demand.

Exhibit E-7
Estimating Duration of Active Demand Resources

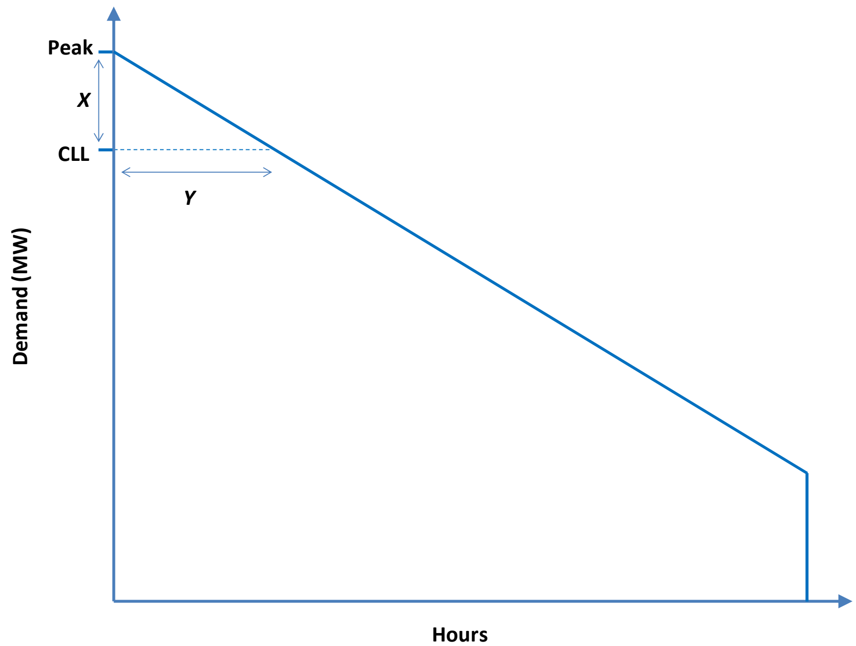


Exhibit E-8
Required Capacity and Duration of Interruptible

State	Combination NTA With Reference DR				Combination NTA With Aggressive DR			
	2015		2020		2015		2020	
	Gap (MW)	Duration (Hrs)	Gap (MW)	Duration (Hrs)	Gap (MW)	Duration (Hrs)	Gap (MW)	Duration (Hrs)
RI	553	221	739	505	539	199	665	337
MA	1504	45	2,536	95	1,472	42	2,272	82
CT	17	3	106	6	0	0	0	0
Total	**2,074**	**NA**	**3,381**	**NA**	**2,011**	**NA**	**2,937**	**NA**

ICF took two approaches to estimating the cost of the incremental reductions. First, ICF calculated the cost of interruptible power in each state based on the energy required and the average VoLL. Industry literature estimates the VoLL at $6,606/MWh for residential customers, $9,578/MWh for commercial customers, and $9,412/MWh for industrial customers.[62] Using the sales by customer class in each state, ICF calculated the average VoLL for all customer

[62] *Stoll, Harry G., Least Cost Electric Utility Planning, June 12, 1989, pages 362-363. ICF uses average of 11 sources cited in the reference document.*

classes, as shown in Exhibit E-9. ICF used the average value because in the CLL analysis load is reduced on a pro rata basis across all customer classes.[63]

Exhibit E-9
Southern New England Sales Ratio and Value of Lost Load

State	Sales By Customer Class			Average VoLL ($/MWh)
	Residential (%)	Commercial (%)	Industrial (%)	
RI	38.5%	48.5%	13.0%	8,412
MA	36.1%	32.9%	31.0%	8,454
CT	42.6%	44.9%	12.5%	8,291

The second approach is based on the ability to obtain the needed reductions from the entities with the lowest cost of interruption, with the assumption that the low cost suppliers of interruption are sited evenly across the sub-zone, i.e., sited the same as the average customer. As noted, for example, if the lowest cost active demand resource is all residential, then it might not be distributed equally across the sub-region. Indeed, it is even possible that the load with the highest unserved cost is located where the reductions occur. Thus, this approach may understate the costs of obtaining interruptible load. This approach also assumes that the increase in cost is linear between FCM and average VoLL estimates.[64] However, as shown in Exhibits E-10 and E-11, this approach may lower the active demand resource cost significantly, i.e., by approximately 72 percent in 2015 and by approximately 62 to 66 percent in 2020.

[63] *To the extent that the least cost interruptible load – that is, those that require the smallest payment or bill discount to participate are already participating in the FCM – this estimate is low. To the extent that residential costs are lower than the average, and assuming residential load is evenly distributed across the region and can be induced to participate, the cost could be lower. The costs shown do not include program management and equipment costs (e.g. automated hourly meters, two-way control, contracting, and marketing costs). This could increase the cost above the values shown.*

[64] *For example, in Exhibit E-10, the VoLL estimate for the existing level of interruptible load of 971 MW is $880/MWh using a 61% performance factor. The average demand of 11,500 MW is associated with the average VoLL estimate from industry studies, and the VoLL at 23,000 MW is nearly twice that level. The 2,982 MW and 3,045 MW estimates are associated with the incremental need in 2015 for the two passive DR cases.*

Exhibit E-10
2015 VoLL Estimate Assuming Low Cost Interruption Location Matches Need

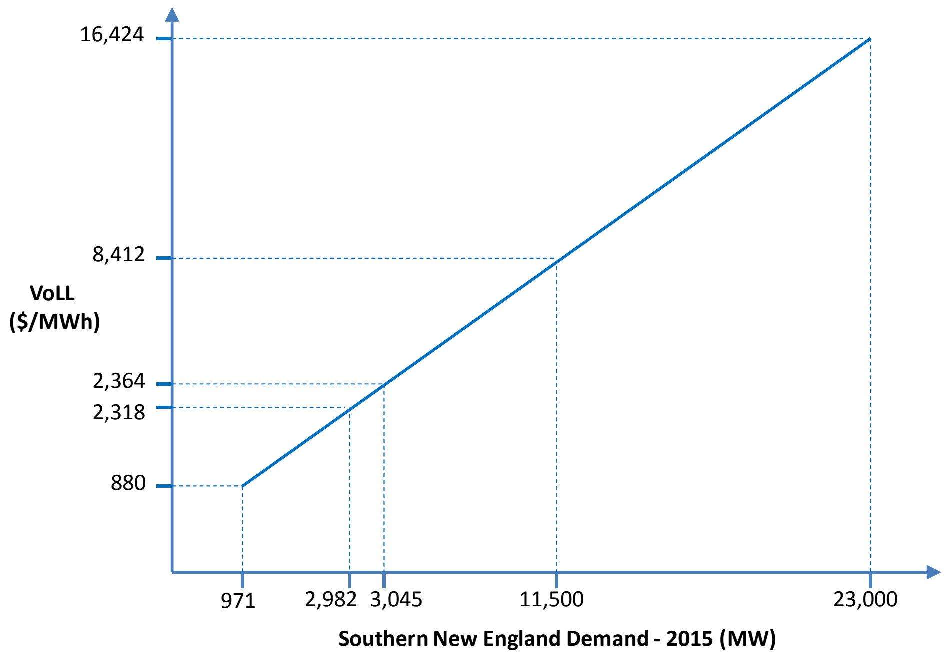
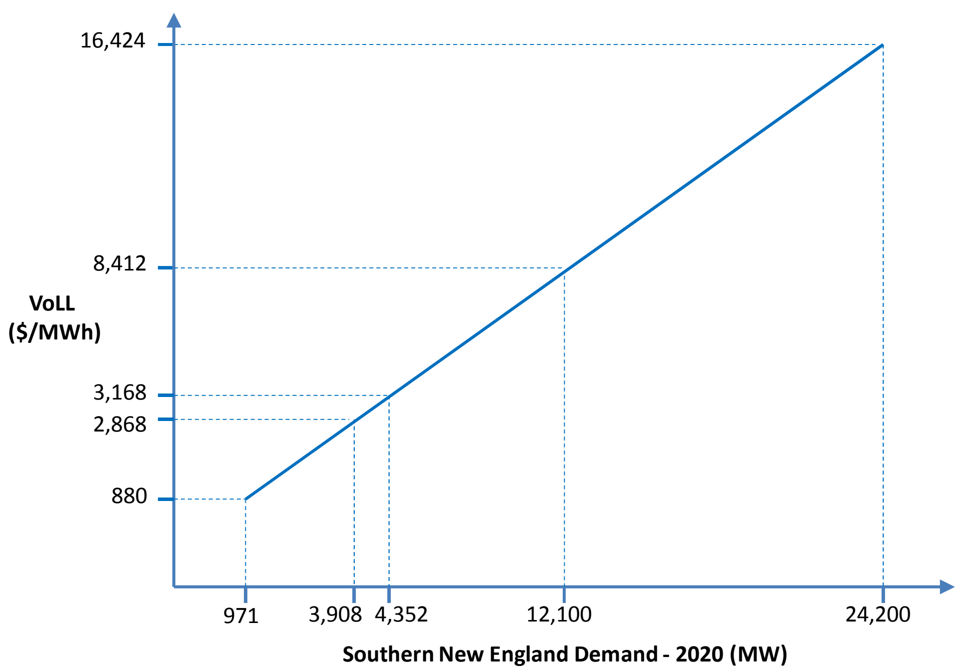


Exhibit E-11
2020 VoLL Estimate Assuming Low Cost Interruption Location Matches Need



IV.3 Active Demand Resource Cost Calculation

IV.3.1 Average VoLL Cost

The total cost of interruptible power in each state depends on the energy required and the VoLL in that state. For example, in Rhode Island, the amount of energy required in 2015 in the Combination NTA with the Reference DR Case is 61,107 MWh (=0.5*553MW*221hours). At an average VoLL of $8,412/MWh, this represents an annual total cost of $514 million for Rhode Island. The cost of interruptible power in each state is shown in Exhibit E-12. In 2015, the costs average $756 million per year. In 2020, the costs average $2,160 million per year.[65] Hence, the costs are very high, especially when one considers that these costs are annual; to be compared to the capital investment costs of Interstate, the present value needs to be calculated.

Exhibit E-12
Cost of Interruptible Power – Annual – Average VoLL Cost

State	Cost Of Interruptible Power ($ million)			
	Combination NTA With Reference DR		Combination NTA With Aggressive DR	
	2015	2020	2015	2020
RI	514	1,570	451	943
MA	286	1,018	261	787
CT	0.2	3	0	0
Total	800	2,591	712	1,730

A comparison of the value of interruptible power to the retail price of power illustrates how impractical it is to achieve the amount of active demand response required to bridge the gap. A typical customer with rates of 15 cents/kWh, sales of 10,000 kWh/year and peak demand of 2 kW would have a customer bill of $1,500/year.[66] To curtail 2kW at peak in 2020, a customer in Rhode Island would have to be paid $4,148 (=$2,124/kW * 2kW).[67] The payment to this customer will be almost 3 times the customer's annual bill. Thus, the customer would, on net, receive much more revenue than he or she would pay. This is because under these conditions the value of power is higher than the price. This highlights how infeasible it is to achieve this amount of active demand resource.

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[65] *Average of Reference and Aggressive.*

[66] *The rates, sales and peak demand are used for illustrative purposes only.*

[67] *See Exhibit E-14*

IV.3.2 Low Cost Interruption

As discussed, if lower cost interruptible load can be obtained, this cost is 62 to 72 percent lower. If it is 70 percent lower, then the payment is $1244 per year. In that case, customers would receive an 83 percent discount on their bill.

V. NTA Cost Calculations

A summary of the capacity and cost of non-transmission resources in the Combination NTAs in 2015 and 2020 are shown in Exhibits E-13 through E-16. In the tables below, ICF assumes that all generation units are conventional natural gas combined cycles. The passive demand resources shown are derived from the Reference DR and Aggressive DR Cases, shown for each state, and the costs are based on the program cost for each state. The active demand resource capacity is the amount of demand resources required to bridge the gap and develop NTA solutions. The cost of active demand resources is based on the average cost of interruptible load, i.e., $8,412/MWh.

Exhibit E-13
Non-Transmission Resource Cost for Combination NTA with Reference DR Case – 2015

State	Passive DR		Generation		Active DR	
	Capacity (MW)	Cost ($/kW)	Capacity (MW)	Cost ($/kW)	Capacity (MW)	Cost ($/kW)
RI	47	3,052	223	1,428	553	929
MA	237	3,052	569	1,605	1504	190
CT	58	2,601	105	1,487	17	12
Total	**342**	**NA**	**897**	**NA**	**2,074**	**NA**

Exhibit E-14
Non-Transmission Resource Cost for Combination NTA with Reference DR Case – 2020

State	Passive DR		Generation		Active DR	
	Capacity (MW)	Cost ($/kW)	Capacity (MW)	Cost ($/kW)	Capacity (MW)	Cost ($/kW)
RI	161	3,052	223	1,428	739	2,124
MA	1,021	3,052	569	1,605	2,536	401
CT	256	2,689	999	1,487	106	28
Total	**1,438**	**NA**	**1,791**	**NA**	**3,381**	**NA**

Exhibit E-15
Non-Transmission Resource Cost for Combination NTA with Aggressive DR Case – 2015

State	Passive DR		Generation		Active DR	
	Capacity (MW)	Cost ($/kW)	Capacity (MW)	Cost ($/kW)	Capacity (MW)	Cost ($/kW)
RI	61	3,052	223	1,428	539	837
MA	263	3,052	569	1,605	1,472	177
CT	81	2,601	105	1,487	0	N/A
Total	**405**	**NA**	**897**	**NA**	**2,011**	**NA**

Exhibit E-16
Non-Transmission Resource Cost for Combination NTA with Aggressive DR Case – 2020

State	Passive DR		Generation		Active DR	
	Capacity (MW)	Cost ($/kW)	Capacity (MW)	Cost ($/kW)	Capacity (MW)	Cost ($/kW)
RI	235	3,052	223	1,428	665	1,418
MA	1,263	3,052	569	1,605	2,272	346
CT	385	2,689	999	1,487	0	N/A
Total	**1,883**	**NA**	**1,791**	**NA**	**2,937**	**NA**

Using the capacity and cost information, ICF calculated the capital cost of the Combination NTA with Reference DR Case at approximately $43.5 billion (see Exhibit E-17). The capital cost of the Combination NTA with Aggressive DR Case was calculated at approximately $32.7 billion (see Exhibit E-18). The costs for these two cases with lower active demand resource costs are $18.7 billion for the Combination NTA with Reference DR Case, as shown in Exhibit E-19 and $15.1 billion the Combination NTA with Aggressive DR Case as shown in Exhibit E-20.

Exhibit E-17
Non-Transmission Resource Cost for Combination NTA with Reference DR – Average DR Cost (Present Value Billion $)

State	Passive DR	Generation	Active DR	Total
RI	0.4	0.3	22.7	23.4
MA	2.7	0.9	14.6	18.2
CT	0.6	1.3	0.0	1.9
Total	**3.7**	**2.4**	**37.3**	**43.5**

Exhibit E-18
Non-Transmission Resource Cost for Combination NTA with Aggressive DR – Average DR Cost (Present Value Billion $)

State	Passive DR	Generation	Active DR	Total
RI	0.6	0.3	14.0	15.0
MA	3.3	0.9	11.4	15.6
CT	0.9	1.3	0.0	2.1
Total	**4.8**	**2.4**	**25.4**	**32.7**

Exhibit E-19
Non-Transmission Resource Cost for Combination NTA with Reference DR – Lower Active Demand Resource Cost (Present Value Billion $)

State	Passive DR	Generation	Active DR	Total
RI	0.4	0.3	8.5	9.2
MA	2.7	0.9	5.5	9.0
CT	0.6	1.3	0.0	1.9
Total	**3.7**	**2.4**	**14.0**	**20.1**

Exhibit E-20
Non-Transmission Resource Cost for Combination NTA with Aggressive DR – Lower Active Demand Resource Cost (Present Value Billion $)

State	Passive DR	Generation	Active DR	Total
RI	0.6	0.3	4.7	5.6
MA	3.3	0.9	3.8	8.0
CT	0.9	1.3	0.0	2.1
Total	**4.8**	**2.4**	**8.5**	**15.8**

The additional assumptions required for the capital cost calculation included:

- Resource life is 30 years.
- Real discount rate is 4.5%.
- Incremental resource requirements for 2016 through 2019 are obtained through linear interpolation of 2015 and 2020 values. After 2020 incremental resources are held fixed at 2020 values.
- Active demand resources are procured annually.

- Passive demand resources are procured once during the study period. For example, in 2015, 47 MW of passive demand resources are required in Rhode Island in the Combination NTA with Reference DR Case. In 2020 the required amount is 161 MW. ICF assumed 47 MW of passive demand resources are added in 2015. From 2016 through 2020, approximately 22.8 MW (=(161MW – 47MW)/5) are added each year, resulting in a total of 161 MW by 2020.

- Only installation costs are included; operating and maintenance costs are excluded. For example, the only supply side cost incurred in Rhode Island in the Combination NTA with Reference DR Case is $318 million (= 233 MW * $1,428/kW * 1000 kW/MW) made in 2015. Since no new incremental generation capacity is required by 2020, no additional supply side cost is incurred over the 30-year study period.

APPENDIX F
Overview of the New England ISO Wholesale Power Market and Transmission

I. Introduction and Organization of This Appendix

The purpose of this Appendix is to provide background information on ISO-NE with emphasis on: (1) transmission planning and the analytic approach used in the study, (2) ISO-NE markets, and (3) supply and demand conditions. The focus is on ISO-NE conditions and their interaction with transmission and NTA options.

The remainder of the Appendix has 11 sub-sections including:

- **Section II – Introduction to ISO-NE (Page 3)** – This section briefly introduces ISO-NE with emphasis on sub-regional features related to transmission limitations.

- **Section III – ISO-NE Transmission Planning (Page 10)** – This section briefly describes transmission planning in ISO-NE. This is intended, in part, to provide background on the study's analytic methodology by discussing the issues of resource adequacy, transmission security, overloads, violations, and load flow analysis.

- **Section IV – ISO-NE Markets (Page 13)** – This section describes ISO-NE markets. Even though ISO-NE operates eight markets, the discussion focuses on two key markets: electrical energy and capacity (i.e., FCM). This is because these two markets account for nearly all the revenue in ISO-NE's markets.

- **Section V – ISO-NE FCM (Page 15)** – This section discusses the ISO-NE capacity market. Special attention is focused on the FCM because prices can be strongly affected by modest changes in transmission and resource levels.

- **Section VI – Recent Rule Changes in ISO-NE FCM (Page 21)** – This section discusses changes in FCM rules that affect NTA contracting and bidding. This is important because NTAs will likely require contracts or programmatic support. In the past, in similar situations, decisions to issue contracts explicitly considered how the resource and its bidding could benefit ratepayers by lowering prices in the FCM. In light of these past situations, the discussion focuses on the changes in FCM market rules which restrict NTA contracts and associated bidding from lowering capacity prices.

- **Section VII – ISO-NE Electrical Energy Market (Page 23)** – This section discusses the ISO-NE electrical energy market with focus on two items. First, the section provides brief background on transmission constraints and locational marginal pricing. Second, the section discusses energy price volatility and the effects of energy market price volatility on NTAs and transmission. For example, NTA contracts will likely be Contract for Differences (CFDs). CFDs provide for "make-up" payments to supplement power plant earnings in the ISO-NE markets. This section explains why earnings and payments might be volatile due to the volatility of ISO-NE electrical energy prices.

- **Section VIII – ISO-NE Electricity Demand (Page 30)** – This section discusses electricity demand. ISO-NE forecasts peak demand growth through 2020. Demand growth directly stresses the transmission system by increasing the potential for overloads. Demand growth also indirectly creates challenges to transmission planning via increasing the amount of required renewable electrical supply. Demand growth contributes to the decision to analyze system performance over the 5-year to 10-year horizon.

- **Section IX – ISO-NE Power Plant Retirements (Page 36)** – This section discusses the potential for power plant retirements which could be prompted by: (1) the age of a large segment of the New England generation fleet, especially oil and gas steam plants, (2) excess capacity, (3) new FCM rules that allow for low FCM prices (i.e., the forthcoming elimination of the FCM price floor), and (4) new environmental regulations. Plant retirements could add to stresses on the transmission grid. Also, even without NTAs, there could be a large need to plan for retirements and new resource additions.

- **Section X – Potential New ISO-NE Supply Resources (Page 38)** – This section discusses the potential new supply resources in the ISO-NE Interconnection Queue. These resources were used in the search for NTA solutions. Even when resources in the Interconnection Queue were combined with aggressive demand side resource assumptions, no NTA was found. Nearly all the fossil resources in the Interconnection Queue are gas-fired combined cycles. One issue raised by the emphasis on gas generation supply is that shortages of natural gas supply deliverability in New England could affect the reliability of power supply. In a shortage, electricity transmission can be useful by allowing for gas power by wire.

- **Section XI – ISO-NE Demand Resources (Page 39)** – This section discusses demand resources. ICF's search for an NTA included aggressive assumptions about incremental passive demand resources and analysis of the reasonableness of meeting the need for additional demand reduction via real time demand response – i.e., active demand resources. No NTA solution was found even when using aggressive assumptions about new demand side resources in combination with plants in the Interconnection Queue. In addition, growing reliance on demand side resources is already a key issue in ISO-NE transmission planning that a DSM based NTA would exacerbate. One aspect is that OP4[68] involves use of active demand side resources. This creates the potential for "fatigue" and loss of interruptible load resources, i.e., as interruption frequency and duration increase, the amount of interruptible load decreases. One concern is that even in the absence of an NTA with incremental demand side resources, in the event of a sudden retirement of generation (e.g., due to elimination of FCM floor, tightened environmental regulations and relaxed rules on economic retirement during the FCA), nearly all local ISO-NE reserves could be demand side. Furthermore, only a portion of the DSM would be active resources. The problem with existing DSM highlights our key conclusion: developing substantial quantities of additional demand resources quickly, as would be needed to provide an NTA to Interstate would be extremely challenging and likely impossible.

- **Section XII – Renewable Portfolio Standards (RPS) (Page 46)** – Ambitious RPS targets are a challenge for transmission planners because the potential demand for renewables exceeds supply in the Interconnection Queue, and more importantly, the location of attractive renewable supply could be remote from a load, further stressing the system. The potential need for renewables by 2020 is extremely large, e.g.,

[68] OP4 is the operating procedures used during shortages.

approximately a ten-fold increase in supply. This potential contributed to one of the sensitivity cases examined.

- **Section XIII – Conclusions**

II. Introduction to ISO-NE

This section introduces ISO-NE. This section also identifies sub-regional features related to transmission limitations.

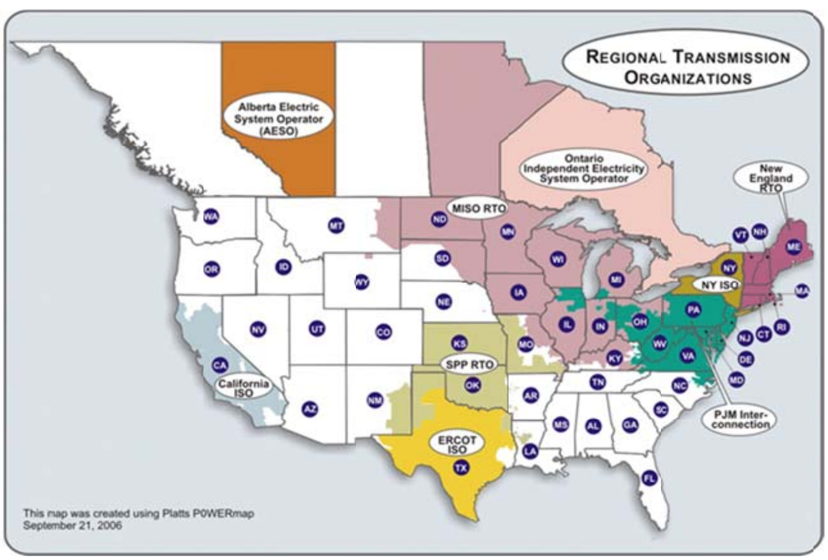
II.1 Responsibilities

Created in 1997, ISO New England (ISO-NE) is a not-for-profit corporation responsible for:

- **Operations** – Day-to-day operation of New England's bulk power generation and transmission system.
- **Markets** – Oversight and administration of the region's wholesale electricity markets.
- **Transmission Planning** – Management of a comprehensive regional bulk power system planning process.

Since February 2005, ISO-NE has operated as a Regional Transmission Organization (RTO). ISO-NE is one of seven U.S. RTOs or ISOs (see Exhibit F-1).

Exhibit F-1
RTOs in North America



Source: FERC

II.2 Description of ISO-NE

As shown in Exhibit F-2, the ISO-NE regional electric power system serves 14 million people living in a 68,000 square-mile area. More than 300 generating units, representing approximately 32,000 megawatts (MW) of total generating capacity, produce electric energy, measured in megawatt-hours (MWh).

Most of these facilities are connected through over 8,000 miles of high-voltage transmission lines. Thirteen tie lines interconnect New England with neighboring New York State and the provinces of New Brunswick and Québec, Canada.

Demand resources now play a significant role in operating the ISO-NE power system. As of summer 2010, approximately 1,900 MW of demand resources representing load reductions and "behind-the-meter" generators are registered as part of ISO-NE's Forward Capacity Market.[69] This level is even higher in later years as discussed below.

Exhibit F-2
Key Facts About New England's Electric Power System and Wholesale Electricity Markets, 2009

- 6.5 million households and businesses; population 14 million
- Over 300 generators
- 32,000 MW of total generation
- Over 8,000 miles of transmission lines
- 13 interconnections to electricity systems in New York and Canada
- About 1,900 MW of demand-resources
- All-time peak demand of 28,130 MW, set on August 2, 2006
- More than 400 participants in the marketplace (those who generate, buy, sell, transport, and use wholesale electricity and implement demand resources)
- $7.5 billion total market value; $5.3 billion energy market
- More than $4.0 billion in transmission investment from 2002 through 2010 to enhance system reliability; approximately $5 billion planned over the next 10 years
- Seven major 345-kilovolt projects constructed in four states

Note: The total load on August 2, 2006, would have been 28,770 MW had it not been reduced by approximately 640 MW, which included a 490 MW demand reduction in response to ISO Operating Procedure No. 4, *Action during a Capacity Deficiency* (OP 4); a 45 MW reduction of other interruptible OP 4 loads; and a 107 MW reduction of load as a result of price-response programs, which are outside of OP 4 actions. More information on OP 4 is available at http://www.iso-ne.com/rules_proceds/operating/isone/op4/OP4_RTO_FIN.doc.

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 16.

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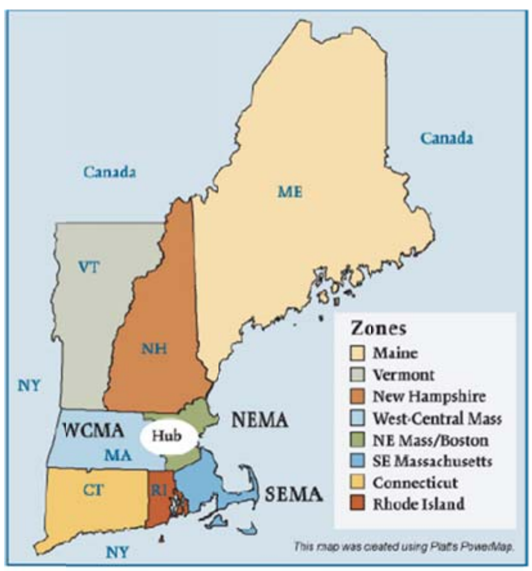
[69] *In exchange for compensation based on wholesale electricity prices, customers in ISO-NE demand-resource programs reduce load continuously or quickly, when instructed, to enhance system reliability or in response to price signals. The 1,900 MW of ISO-NE demand resources do not include energy efficiency provided by other customer-based programs that are outside the ISO-NE markets or are otherwise unknown to ISO.*

II.3 Selected Sub-Regional Features

The ISO-NE power market has important sub-regional features that emphasize the importance of ISO-NE's transmission grid and its capability for intra-regional transmission. These sub-regional features result in sub-regional resource mix diversity, local imbalances between supply and demand, and smaller market sizes. Key features include:

- **States** – ISO-NE encompasses the six states of Maine, New Hampshire, Vermont, Connecticut, Massachusetts and Rhode Island.
- **Load Zones** – New England is divided into the following eight load zones used for wholesale market billing: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA). See Exhibit F-3.
- **Hub** – There is also a central hub as depicted in Exhibit F-3. The *Hub* is a collection of locations that has a price intended to represent an uncongested price for electric energy, facilitate trading, and enhance transparency and liquidity in the marketplace.
- **Interconnections** – It is bordered by and interconnected with the New York ISO-NE (NYISO), Hydro Quebec, and New Brunswick.

Exhibit F-3
ISO-NE Load Zones



Source: FERC

- **Nodes, Hubs, and Zones** – The pricing points on the system include individual generating units, load nodes, *load zones* (i.e., aggregations of load pnodes within a specific area), and the Hub.[70] In New England, generators are paid the Locational Marginal Price (LMP) for electric energy at their respective nodes, and participants serving demand pay the price at their respective load zones.[71]

  Import-constrained load zones are areas within New England that do not have enough local resources and transmission-import capability to serve local demand reliably or economically. *Export-constrained* load zones are areas within New England where the available resources, after serving local load, exceed the areas' transmission capability to export the excess electric energy.

- **Capacity Zones** – A *capacity zone* is a geographic sub-region of the New England Balancing Authority Area that may represent load zones that are export constrained, import constrained, or contiguous—neither export nor import constrained. Capacity zones are used in the Forward Capacity Auctions (FCAs) that set the price in the FCM. ISO-NE is likely to have each of the eight load zones become capacity zones and may eventually add more.

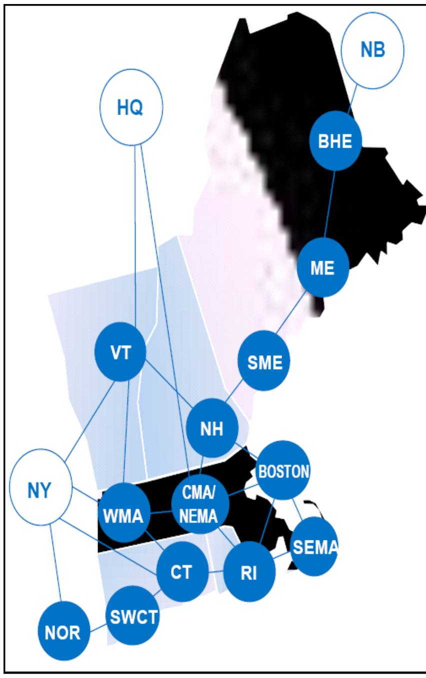
- **Reserve Zones** – The region also currently has four *reserve zones*—Connecticut (CT), Southwest Connecticut (SWCT), NEMA/Boston, and the rest of the system (Rest-of-System, ROS) (i.e., the area excluding the other, local reserve zones). They are used to set prices in forward operating reserve markets.

- **RSP Transmission Planning Zones** – ISO-NE is also characterized as comprising thirteen Regional System Plan (RSP) zones, which provide a zonal configuration generally indicative of transmission constraints (see Exhibit F-4).

[70] *Load zones can also have the same boundaries as reliability regions, which are intended to reflect the operating characteristics of, and the major constraints on, the New England transmission system. See Market Rule 1, Section III.2.7 of the ISO-NE tariff; http://www.iso-ne.com/regulatory/tariff/sect_3/_mr1_sect_1-12.pdf.*

[71] *The ISO-NE tariff allows loads that meet specified requirements to request and receive nodal pricing.*

Exhibit F-4
Geographic Scope: New England Regional System Plan (RSP) Areas

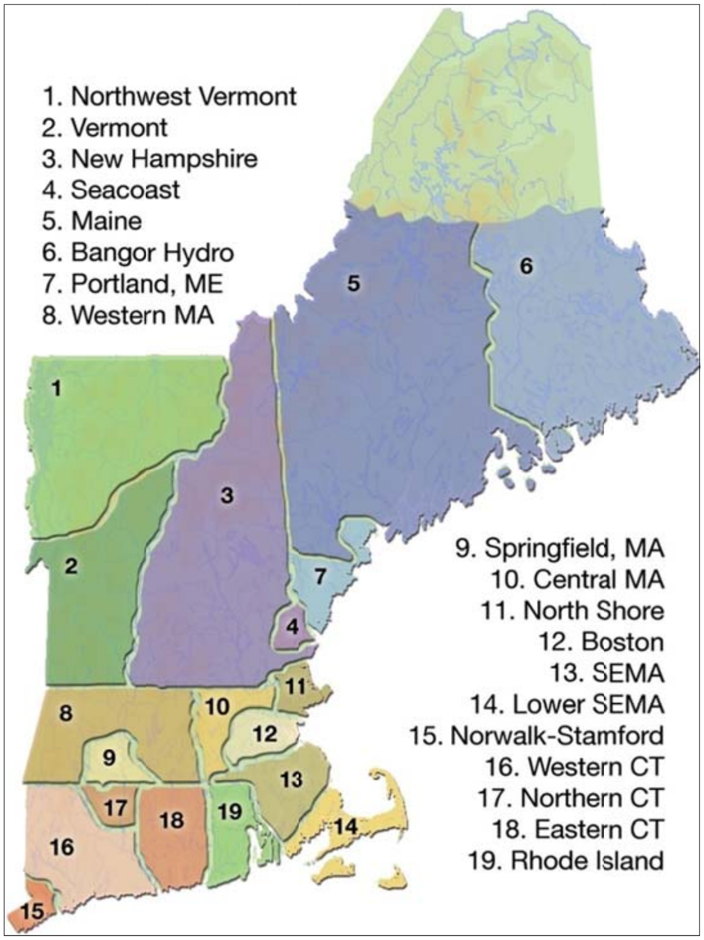


Subarea Designation	Region or State
BHE	Northeastern Maine
ME	Western and central Maine/ Saco Valley, New Hampshire
SME	Southeastern Maine
NH	Northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine
VT	Vermont/southwestern New Hampshire
BOSTON (all capitalized)	Greater Boston, including the North Shore
CMA/NEMA	Central Massachusetts/ northeastern Massachusetts
WMA	Western Massachusetts
SEMA	Southeastern Massachusetts/ Newport, Rhode Island
RI	Rhode Island/bordering Massachusetts
CT	Northern and eastern Connecticut
SWCT	Southwestern Connecticut
NOR	Norwalk/Stamford, Connecticut
NB, HQ, and NY	New Brunswick (Maritimes), Hydro-Québec, and New York external balancing authority areas

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 20.

- **Demand-Resource Dispatch Zones** – A *demand-resource dispatch zone* is a group of nodes (i.e., pricing points) within a load zone that is used to define and dispatch real-time demand-response resources or real-time emergency generation (RTEG) resources. These allow for a more granular dispatch of active demand resources at times, locations, and quantities needed to address potential system problems without unnecessarily calling on other active demand resources. Exhibit F-5 shows the dispatch zones the ISO-NE uses to dispatch FCM active demand resources.

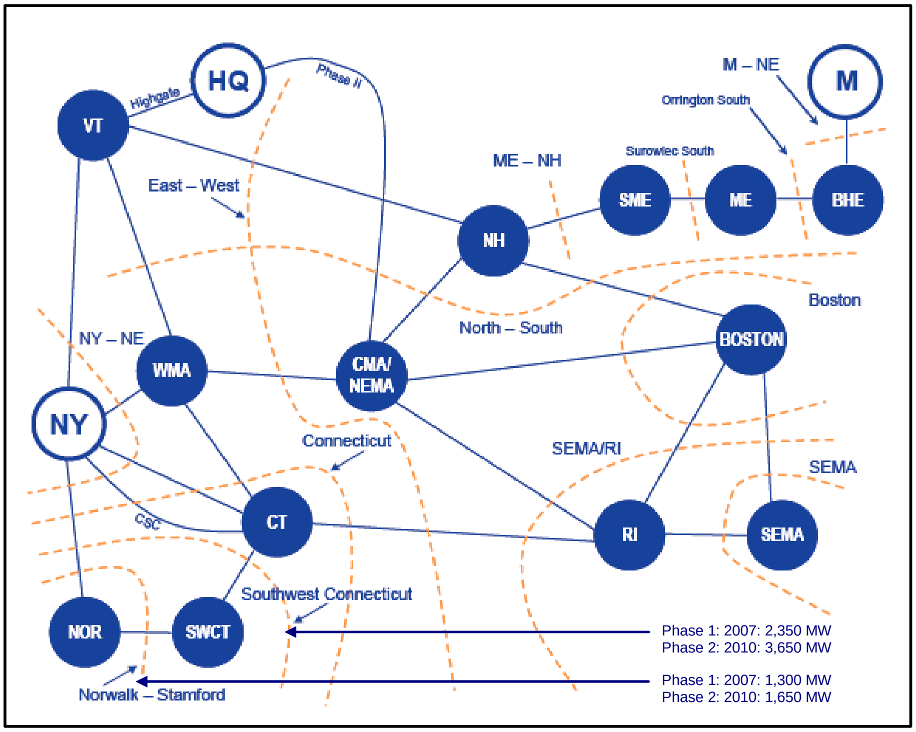
Exhibit F-5
Active-Demand Resource Dispatch Zones in the ISO New England System



Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 142.

- **East-West and North-South Interfaces** – Exhibit F-6 highlights the role of inter-regional and intra-regional issues in ISO-NE. Key transmission interfaces and RSP areas are shown.

Exhibit F-6
ISO-NE and Connecticut Transmission Constraints

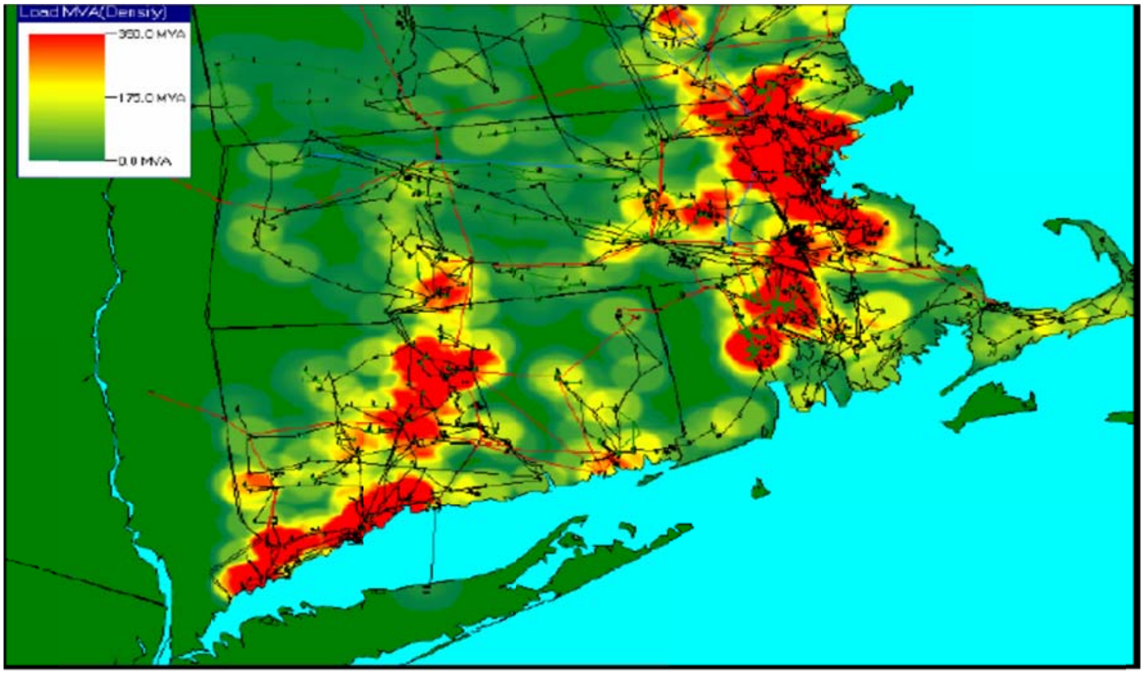


Source: ISO-NE*, Regional System Plan*, October 2007

Exhibit F-6 also shows a North-South line which divides southern and northern New England, and an East-West line which divides eastern and western New England (both are dotted lines). The distribution of peak loads in the New England area is approximately 20% in the Northern states of Maine, New Hampshire and Vermont, and 80% in the Southern states of Massachusetts, Connecticut and Rhode Island. Even though the Northern states cover a greater geographic area, the density of population causes the southern load to be larger.

The map shown in Exhibit F-7 depicts load density for the geographic area of Southern New England. As shown in this figure, a substantial number of significant concentrations of loads exist – Boston and its suburbs, Central Massachusetts, Springfield, Rhode Island, Hartford/Central Connecticut, and Southwest Connecticut.

Exhibit F-7
Southern New England Load Concentrations

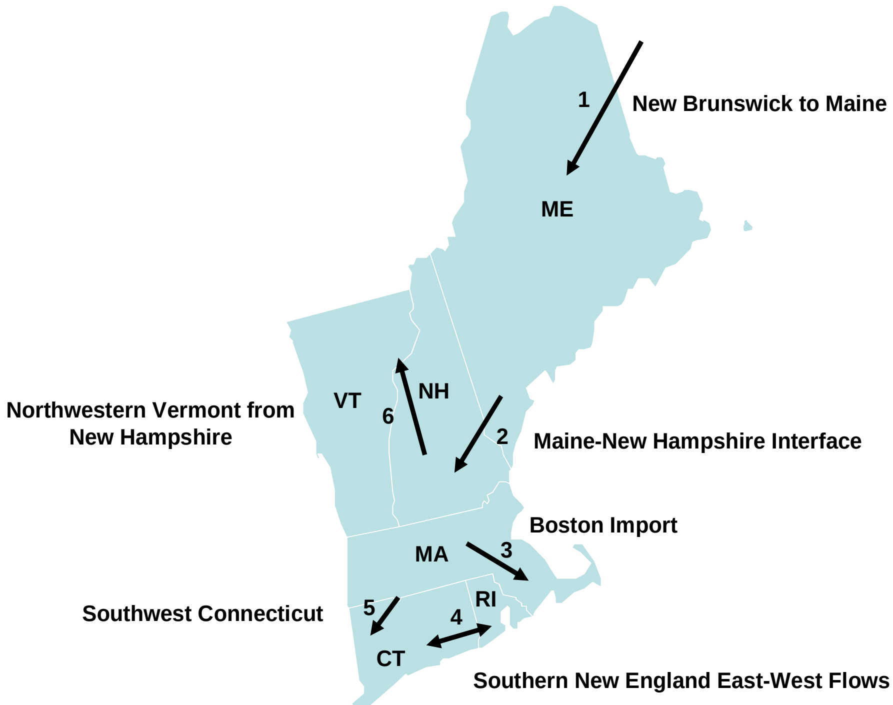


Source: Southern New England Transmission Reliability Report

The east-west transmission interface divides New England roughly in half. Vermont, Southwestern New Hampshire, Western Massachusetts, and Connecticut are located to the west of this interface; while Maine, Eastern New Hampshire, Eastern Massachusetts, and Rhode Island are to the East. Exhibit F-8 also shows that there is much load on either side of the constraint. In the early 1990s, this interface was important to monitor in day-to-day operations because of constraints in moving power from the significant generation in the west to Boston and its suburbs in the East. Following the influx of new generation in the East in the late 1990s, this interface now becomes constrained in the opposite direction, from east to west.

In its National Electric Transmission Congestion Study, the DOE identified six major transmission constraints in New England including southern New England East-West flows (see Exhibit F-8).

Exhibit F-8
New England Transmission Constraints



Source: DOE, National Electric Transmission Congestion Study

II.4 Sub-Regional Supply/Demand Balance

As Exhibit F-9 illustrates, supply and demand balance in ISO-NE varies across sub-regions. Boston and Southwest Connecticut are the major demand centers with insufficient local generation to supply load, while Rhode Island and Western Massachusetts have excess supply. Though not shown, Maine and rest-of-pool also have excess.

Exhibit F-9
ISO-NE Demand/Supply Balance – 2011 Projected

Region	Net Internal Demand* (MW)	Total Installed Capacity (MW)	(Installed) Reserve Margin (%)	Total Net Dependable Capacity (MW)	(Net Dependable) Reserve Margin (%)
Connecticut	3,381	3,910	16%	3,895	15%
SWCT	2,249	2,686	19%	2,676	19%
Rhode Island	2,478	3,782	53%	3,782	53%
Boston	5,592	3,416	-39%	3,411	-39%
WMA	2,135	2,119	-1%	1,875	-12%
ISO-NE	26,776	32,207	20%	31,365	17%

*Net Internal Demand is from CELT 2011 50/50 Peak Demand Net PDR

Source: ISO-NE

ICF INTERNATIONAL

III. ISO-NE Transmission Planning

This section provides background on transmission planning, reliability, and the analytic methods used in the study.

III.1 Reliability

ISO-NE has lead responsibility for transmission planning in New England and is subject to FERC regulations in this regard. A key focus of transmission planning is reliability. The North American Electric Corporation (NERC) describes two aspects of reliability:

- **Adequacy** – Adequacy means having sufficient resources to provide a continuous supply of electricity in spite of scheduled or unscheduled outages, e.g., meeting the ISO-NE ICR or in other regions, a planning reserve margin. Typical U.S. planning reserve margins are 12 to 20 percent of peak. In a simplified example, a utility with a summer peak demand of 10,000 MW, and a target reserve margin of 15 percent must have at least 11,500 MW of capacity available at peak. One explanation of the range is that some regions have greater likely access to resources from neighboring regions, and hence, can have lower resulting reserve margins. Another explanation is that some regions with high DSM reliance have chosen to have higher planning reserve margins.

- **Security** – Security is the ability of the power system to withstand sudden, unexpected disturbances, e.g., to operate without thermal violations even during periods of high demand. Detailed transmission security analyses examine the potential for thermal violations (transmission line overloads) and voltage violations as a predicate to solving these violations.

III.2 Transmission Security and Overloads

Potential overloads identified using AC load flow models threaten customer service. When overloads occur, operator action may be taken to relieve the overload; if the overload persists, protective devices (i.e., devices similar to circuit breakers) may take the overloaded line out of service to prevent system damage. Emergency actions taken by operators or automatic measures to relieve one line's overload could overload other transmission system elements, worsen system conditions, and result in a cascade of electric service interruptions. Therefore, the system must be designed to operate within limits under anticipated stresses and outages.

Overloads are violations of federally mandated reliability regulations. Each identified potential overload violates reliability standards and criteria of (1) the North American Electric Reliability Corporation (NERC), which is the U.S. Electric Reliability Organization (ERO), (2) the Northeast Planning Coordinating Council (NPCC), and (3) ISO-NE.

Unexpected loss of power plants can increase the number and severity of potential overloads. For example, the owner of the Salem Harbor power plant recently confirmed that it will be retired by June 1, 2014, notwithstanding requests that it continue to be operated for reliability purposes. Salem Harbor's retirement increases the number of potential overloads found in the ISO-NE "base case".

Other resource uncertainties also challenge the system. For example, ISO-NE has already determined that the system cannot plan assuming the Vermont Yankee nuclear plant is available due to uncertainties about its future. By 2020, other aging power plants including especially oil and gas steam plants may also retire, adding to potential overloads and violations.

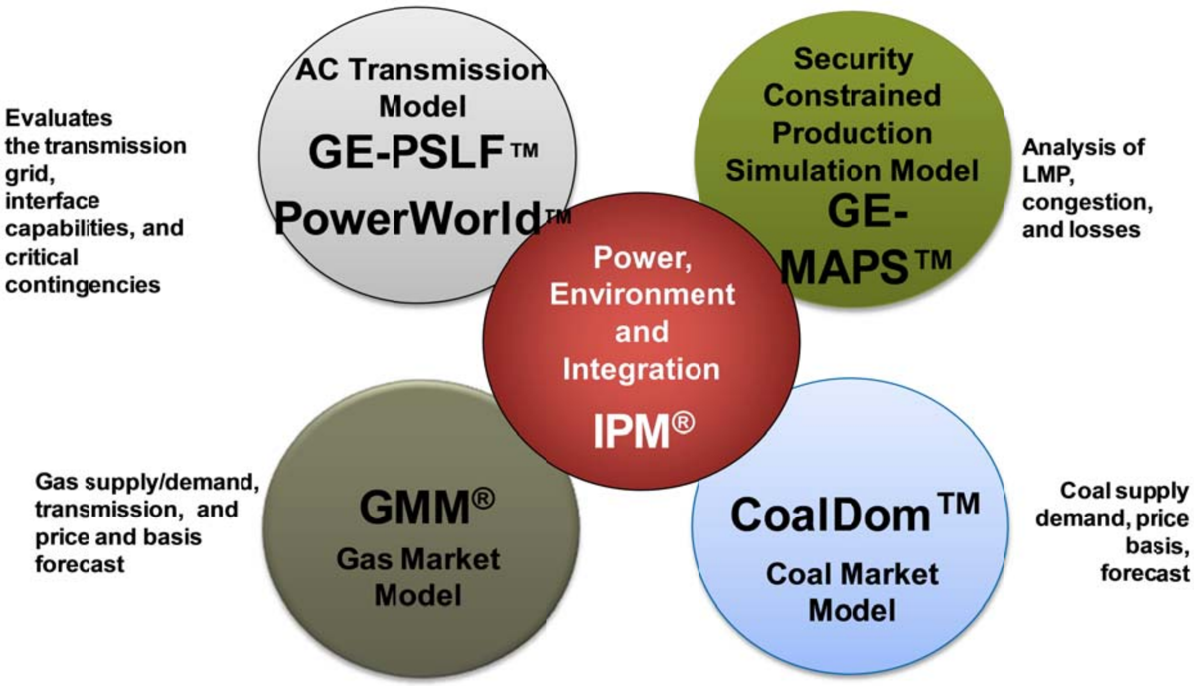
III.3 Transmission Modeling

Transmission security analysis requires detailed power flow modeling and contingency analysis, e.g., AC load flow modeling. Models simulate actual transmission line flows and determine the ability of the system to operate reliably under many different system conditions. Studies are conducted by system planners to ensure the transmission system continues to operate reliably under varying conditions. Also, this modeling is similar to the analysis of system operators as they respond to the implications of lost transmission lines, loss of generation injections, and other contingencies.

The models used by ICF are representative of the differences between transmission security, adequacy, and nodal pricing (see Exhibit F-10). The models most focused on electric power (the top three in the Exhibit) are:

- **GE PSLF and PowerWorld Simulator** – These AC power flow models allow for an analytic approach that is an engineering characterization of actual transmission grid operations for a snapshot in time. Generation injections, actual line flows and substation voltages can be determined under N-0, N-1, and N-1-1 contingency conditions, e.g., N-0 or no outages, N-1 a set of scenarios in which each has an outage at one element, and N-1-1, a set of scenarios with outages at two elements. This is the type of modeling tool used for identifying overloads in this study.
- **IPM®** – IPM® is an optimization tool which addresses resource adequacy with zonal reserve margin requirements. The model has a simplified D.C. transmission grid treatment and requires each sub-region to meet a reserve margin. The reserve levels are ultimately based on a probabilistic loss of load probability and analysis done outside the model. The model also optimizes new builds, retirements, retrofits, and mothballing.
- **GE Energy MAPS™ Software (MAPS[1])** – This model has a much more detailed treatment of transmission than IPM and is focused on transmission congestion, but assumes voltages remain adequate under all conditions. It is not a tool for security analysis, but for assessing nodal prices.
- **GMM and CoalDom** – These models are examples of models used to assess fuel industries. As noted, gas supply and environmental regulations on coal use are increasingly important issues.

Exhibit F-10
AC Load Flow Modeling and Other Modeling Tools – ICF Example



III.4 ISO-NE Transmission Planning and Transmission Solutions

When planners identify the potential for overloads on the transmission system, the goal of the ISO-NE process is to give market responses every opportunity to solve the problem. ISO-NE will propose a "backstop" transmission solution if no other solution is forthcoming. Once the transmission solution has been identified, states are interested in understanding both the proposed solution and the NTA options, if any.[72]

IV. Introduction ISO-NE Markets

ISO-NE operates eight wholesale electricity markets. They are:[73]

- **Day-Ahead Energy Market** – allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time.

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[72] *The 2010 RSP states that if stakeholder responses to market signals are not forthcoming or adequate to meet identified system needs, ISO-NE is required to conduct subsequent transmission planning to develop regulated transmission solutions that determine transmission infrastructure that can meet the identified needs. However, ISO-NE does not have the authority to build needed resources or transmission. With input from stakeholders, ISO-NE prepares Needs Assessments, which identify the needs for transmission solutions, and Solutions Studies, which describe options for meeting the identified needs. Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 14.*

[73] *For more information on New England wholesale electricity markets, see the ISO's 2009 Annual Markets Report (AMR09) (May 18, 2010); http://www.iso-ne.com/markets/mktmonmit/rpts/index.html.*

- **Real-Time Energy Market** – coordinates the dispatch of generation and demand resources to meet the instantaneous demand for electricity.
- **Forward Capacity Market (FCM)** – ensures the sufficiency of installed capacity, which includes demand resources, to meet the future demand for electricity by sending appropriate price signals to attract new investment and maintain existing investment both where and when needed.[74]
- **Financial Transmission Rights (FTRs)** – allows participants to hedge against the economic impacts associated with transmission congestion and provides a financial instrument to arbitrage differences between expected and actual day-ahead congestion.
- **Ancillary Services**
    - **Regulation Market** – compensates resources that the ISO-NE instructs to increase or decrease output moment by moment to balance the variations in demand and system frequency to meet industry standards.[75]
    - **Forward Reserve Market (FRM)** – compensates generators for the availability of their unloaded operating capacity that can be converted into electric energy within 10 or 30 minutes when needed to respond to system contingencies, such as unexpected outages.[76]
    - **Real-time reserve pricing** – compensates on-line generators that offer their electric energy above the marginal cost for the increased value of their energy when the system or portions of the system are short of reserves. It also provides efficient price signals to generators when redispatch is needed to provide additional reserves to meet requirements.
    - **Voltage support** – compensates resources for maintaining voltage-control capability, which allows system operators to maintain transmission voltages within acceptable limits.

This report focuses on two markets, the Energy Market and the Capacity Market, and often treats the Day Ahead and Real Time as one market to simplify discussion. This is because energy and capacity markets account for nearly all revenues earned by resources. The pie chart provides the historical revenues for a representative combined cycle unit with a 7,000 Btu/kWh heat rate (see Exhibit F-11). Energy revenue comprises the greatest share of gross margin. The capacity market provides a smaller share of total revenues to most generators as

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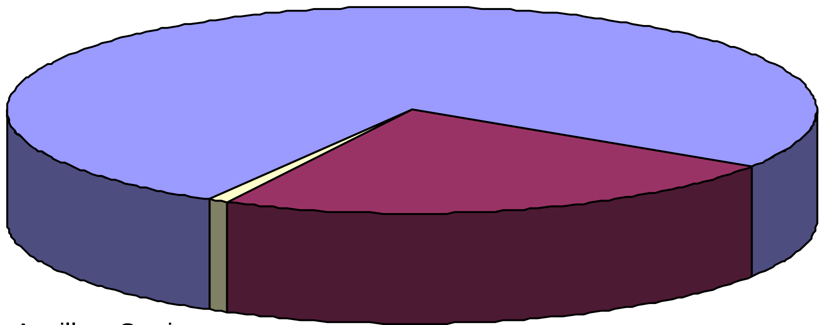
[74] Installed capacity is the megawatt capability of a generating unit, dispatchable load, external resource or transaction, or demand resource that qualifies as a participant in the ISO's Forward Capacity Market according to the market rules. Additional information is available at http://www.iso-ne.com/markets/othrmkts_data/fcm/index.html.

[75] Regulation is the capability of specially equipped generators to increase or decrease their generation output every four seconds in response to signals they receive from the ISO-NE to control slight changes on the system.

[76] Unloaded operating capacity is operational capacity not generating electric energy but able to convert to generating energy. A contingency is the sudden loss of a generation or transmission resource. A system's first contingency (N-1) is when the power element (facility) with the largest impact on system reliability is lost. A second contingency (N-1-1) takes place after a first contingency has occurred and is the loss of the facility that then has the largest impact on the system.

compared to the energy market, but it is an important driver of net margin for intermediate and peaking plants. Ancillary services revenue provide less than one percent of total gross margins.

Exhibit F-11
Revenue Types as a Percentage of Gross Margin (Combined Cycle Unit)



V. Introduction To ISO-NE FCM

Prices in the FCM are very sensitive to modest changes in transmission and resources. Thus, special attention is focused on this market.

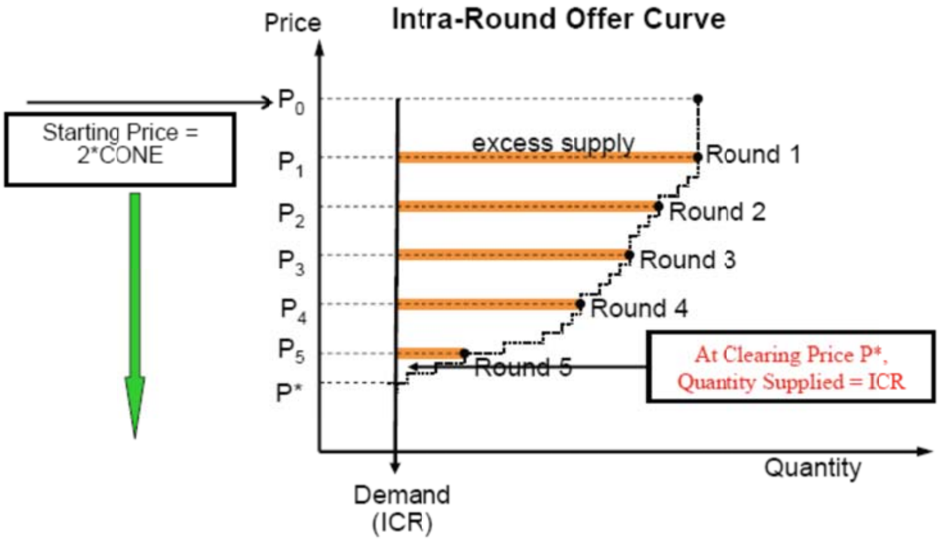
V.1 Purpose and Structure

Capacity markets are regulatory constructs that assign a value to the ability to supply energy during periods of system scarcity. Capacity markets are needed because of regulation of the U.S. electric energy markets – in the form of system reliability targets, market power price mitigation, and price caps significantly limit the market's ability to correctly value energy procured when supplies are tight.

Put another way, ISO-NE's Forward Capacity Market (FCM) is designed to supplement the earnings of power plants to ensure the reliability of the New England electricity grid. This supplement is especially important for peaking units whose energy revenues are lowest. However, having a single price for the same product provides incentives to maximize the ability to provide the product, and hence, maximizes efficiency.

Capacity is procured via a Forward Capacity Auction (FCA), a descending clock auction (see Exhibit F-12). The auction is conducted 40 months before the start of a given commitment period to allow time for new resources to be developed and built. The length of the Capacity Supply Obligation (CSO) is a minimum of one year. New resources can select multiple year commitments thereby extending the period of fixed and known capacity pricing. Commitments to these new resources are intended to be sufficiently certain and binding to facilitate new project financing. ISO-NE can qualify resources to participate in the FCA including existing and new generation assets, demand-response, and alternative energy sources.

Exhibit F-12
Descending Clock Auction Mechanics



Source: ISO-NE

The FCM is designed so that the market price is set by the lowest priced new capacity that meets the region's needs for electricity. In periods in which no new resources are needed, the last resource satisfying the ICR quantity (i.e., the demand) could be an existing resource. The first such auction occurred in February 2008 and had a commitment period of June 2010 to May 2011. The fifth auction occurred in June 2011 and had a commitment period of June 2014 to May 2015.

V.2 FCM Pricing and Price Volatility

Theoretically, one would expect significant volatility in capacity prices and great sensitivity to changes in supply, demand and transmission. This is because when supply exceeds demand, i.e., when there is excess capacity, the marginal required supplemental revenue is likely to be set by an existing unit (e.g., a peaking plant), and is limited to the unit's going forward costs (e.g., property taxes, insurance, labor, maintenance) net energy market earnings. On the other hand, when demand exceeds supply (i.e., there is a shortage), prices are set by the cost of new units, which includes recovery of and on capital plus non-fuel O&M net energy margins. This cost level greatly exceeds the cost of non-fuel O&M at existing peaking units, creating the potential for a large price jump.

An example of capacity market volatility was the 360% increase in PJM's Reliability Pricing Model (RPM) forward capacity market in the RTO region between the 2010 and 2011 auction.

This sensitivity of the capacity price is important because the addition of resources and transmission has the potential to affect the capacity price. This is especially important due to zonal sub-markets which are smaller than the ISO-NE market as a whole, further increasing the potential for transmission and resource changes to affect capacity prices. However, as discussed later, this potential has recently been greatly curtailed due to FCM rule changes which affect NTA bidding.

Since the inception of the ISO-NE FCM, ISO-NE has conducted five auctions under the FCM covering the June 2010-May 2015 period. There has also been a transition period from the previous approach. However, in spite of the potential for capacity price volatility, FCM prices have exhibited little volatility (see Exhibit F-13). Significantly, FCM prices cleared at the floor price in each of the five auctions to date. The floors were to expire after FCA#3 but were extended by FERC and were applicable in the most recent auction (FCA#5).

Exhibit F-13
FCM Pricing: Transition Period and Cleared Forward Capacity Auctions

Procurement Type	Obligation Period	Cleared Price – ICAP[1] (Nominal$/kW-yr)	Prorated Payment[2] (Nominal$/kW-yr)
Transition Period-1	Dec 2006 – May 2007	34.8	34.8
Transition Period-2	Jun 2007 – May 2008	34.8	34.8
Transition Period-3	Jun 2008 – May 2009	42.8	42.8
Transition Period-4	Jun 2009 – May 20100	46.7	46.7
FCA-1	Jun 2010 – May 2011	54.0	51.0
FCA-2	Jun 2011 – May 2012	43.2	37.4
FCA-3	Jun 2012 – May 2013	35.4	30.4
FCA-4	Jun 2013 – May 2014	35.4	30.2
FCA-5 (Preliminary Results)	Jun 2014 – May 2015	38.5	NA

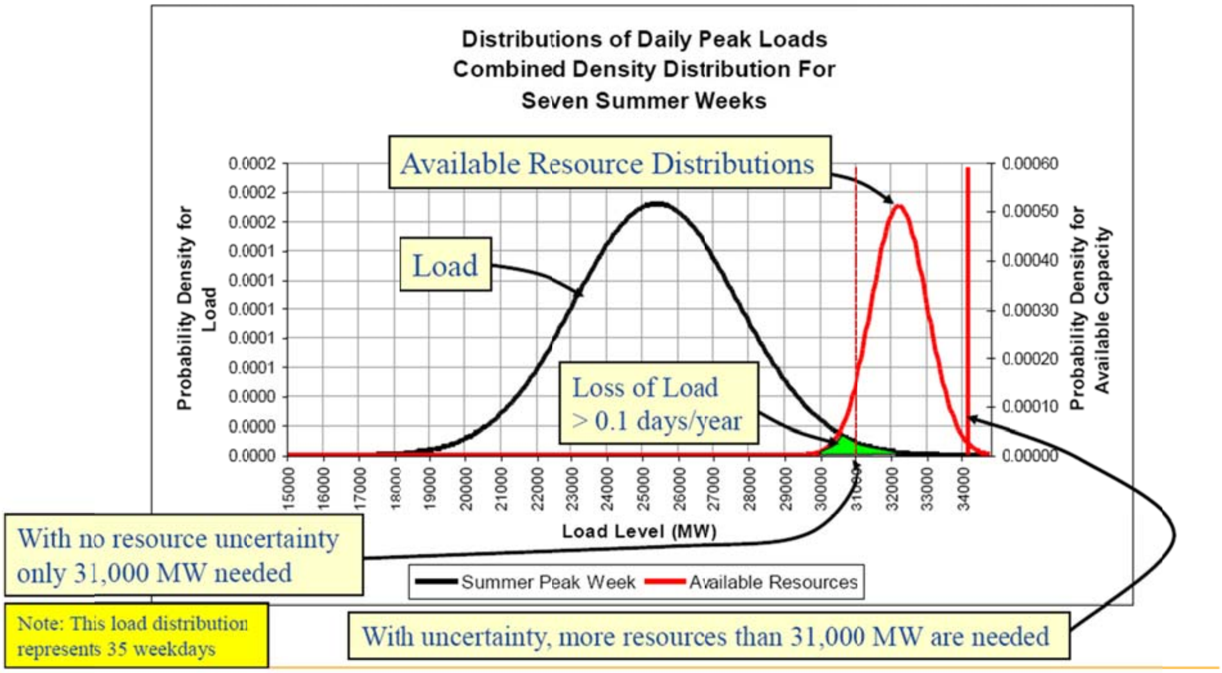
[1] Transition period payments were converted to ICAP by assuming 5% generic EFORd.

[2] When the FCA clears at the floor with excess capacity (which has been the case for the first four FCAs), auction participants who bid at or below the floor can opt to receive capacity payments at the floor price, but only for a prorated portion of their total capacity bid.

V.3 Market Supply and Demand Conditions

The FCM procures capacity to meet Installed Capacity Requirements (ICRs) which are driven strongly by peak demand levels. ICRs are derived using a probabilistic model that accounts for load probability distributions, size, and EFOR for the resources (see Exhibit F-14). The increase in FCM requirements between FCA #1 and FCA #5 has been modest at 225 MW/year on average. This low growth rate has also contributed to low price volatility. Part of this low growth is due to the most recent US economic recession.

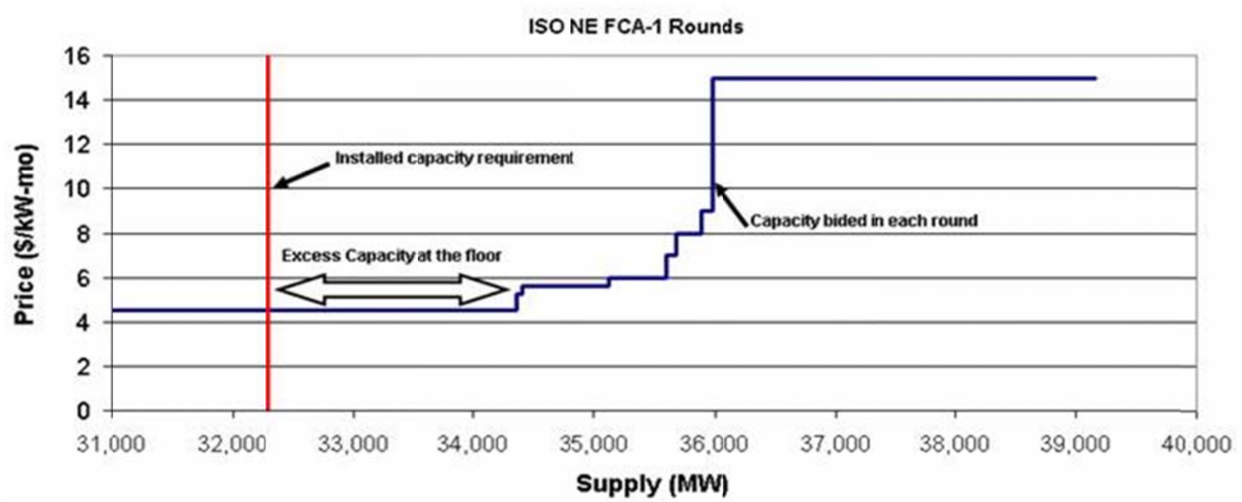
Exhibit F-14
ICR Methodology – Example



Source: NE-ISO

As noted, all the auctions have had price floors and excess capacity, dampening price volatility. The first FCM auction price cleared at the floor level of $4.5/kW-mo (see Exhibit F-15). There was excess capacity at the resulting price, and hence, the floor price of $4.5/kW-mo was further prorated for the 1,772 MW of excess capacity that cleared in the auction (relative to the 32,305 MW required).

Exhibit F-15
ISO-NE FCA-1 Rounds



Source: ISO-NE

The excess supply increased from FCA #1 to FCA #4, when it reached 5,374 MW. The amount of excess capacity decreased in FCA #5, the most recent auction, to 3,718 MW (see Exhibit F-16). This is still more than 10 percent above required levels.

The demand resource level (DR) has increased in every auction (+1,189 cumulatively) while the supply has only modestly increased (+550 MW). This small net increase in supply is in spite of approximately 1,100 MW of Connecticut contracted resources being added: Kleen Energy – 620 MW; Devon 15-18 – 187 MW; Middletown – 186 MW; and New Haven Harbor 2-4 – 130 MW. FCA #5 was the first auction to have a generation decrease (-808 MW).

Exhibit F-16
Results of the First Five Forward Capacity Auctions

Auction[1]	Total Qualified (MW)	Cleared Genrtn (MW)	Cleared DR[2] (MW)	Cleared Imports (MW)	Total Capacity Acquired (MW)	Capacity Required (MW)	Floor Price[3]	Excess Supply (MW)	Prorated Price[4]
FCA #1 (2010/11)	39,165	30,865	2,279	933	34,077	32,305	$4.50	1,772	$4.25
FCA #2 (2011/12)	42,777	32,207	2,778	2,298	37,283	32,528	$3.60	4,755	$3.12
FCA #3 (2012/13)	42,745	32,228	2,867	1,901	36,996	31,965	$2.95	5,031	$2.54[5]
FCA #4 (2013/14)	40,412	32,247	3,261	1,993	37,501	32,127	$2.95	5,374	$2.52[6]
FCA #5 (2014/15) (Initial Results)	40,077	31,439	3,468	2,011	36,918	33,200	$3.21	3,718	$2.86

[1] Initial results from each auction; amounts will change with monthly and annual reconfiguration auctions.

[2] Demand resource totals include a 600 MW cap on real-time emergency generation resources.

[3] Floor price is per kilowatt-month.

[4] Prorated price is per kilowatt-month.

[5] Prorated price in Maine for 2012/2013 is $2.47/kW-month.

[6] Prorated price in Maine for 2013/2014 is $2.34/kW-month.

V.4 Forward Capacity Market – Zones

While the FCM, in theory, allows for capacity prices to reflect the locational value of reliability in transmission constrained zones within New England, historical results generally showed only one capacity value within ISO-NE or two with Maine clearing separately but with prices similar to the rest of ISO-NE's price. This is in part because in the past, zonal markets were only analyzed if the region had a capacity shortfall before the auction. The potential of units to withdraw for economic reasons during the auction was not considered in determining whether there should be analysis of the zonal market. However, under new rules, ISO-NE will follow a new policy of modeling "all zones all the time." Hence, there is greater potential for zonal price differences.

V.5 Sub-Regional Local Resource Requirements – New Rules

While zonal price differences have been practically non-existent, new rules combined with other factors are increasing demand for local capacity supply as opposed to imports from other zones. This places greater emphasis on transmission to prevent zonal price separation. If there was a large amount of transmission capacity between zones, any potential price difference would result in more imports or exports until the price difference was eliminated. Also, local capacity sourcing requirements would be smaller and less likely to create price differences because the local zonal reliance on imports would be greater. New rules also increase the sensitivity of capacity prices to changes in resources and transmission because the zonal markets can be very small compared to ISO-NE.

While the ICR addresses New England's total capacity requirement, assuming the system overall has no transmission constraints within the region, certain subareas within New England are affected by limitations in the ability to export or import power within the region. To address the subarea reliability impacts of these constraints, the ISO-NE determines the maximum capacity limit (MCL) and local sourcing requirement (LSR) for certain subareas within New England. An *MCL* is the maximum amount of capacity that can be procured in an export-constrained load zone to meet the total ICR for the New England region. An *LSR* is the minimum amount of capacity that must be electrically located within an import-constrained load zone to meet the ICR.

On February 22, 2010, as part of a larger package of proposed changes, ISO-NE filed rule changes to revise the methodology for calculating the LSR for import-constrained capacity zones starting with FCA #4.[77] Because the system must meet both the resource adequacy and transmission security requirements, the rule changes would require both resource adequacy and transmission security constraints to be respected for each import-constrained zone. These revisions consider both the use of the probabilistic local resource adequacy criteria previously used to determine the LSR for capacity zones and the deterministic transmission security criteria ISO-NE uses to maintain system operational reliability when reviewing *delist bids* for the FCA (i.e., bids submitted by existing capacity resources interested in being removed from the FCA).[78] The LSR for an import-constrained zone is now defined as the amount of capacity needed to satisfy the higher of the probabilistic local resource adequacy (LRA) requirement or the deterministic transmission security analysis (TSA) requirement.

[77] *The rule changes pertain only to import-constrained load zones. Each export-constrained load zone is modeled as a separate capacity zone in the FCA; the ISO-NE did not propose any change to these provisions.*

[78] *To enhance the regional system planning process, the ISO-NE is also analyzing the impact of proposed transmission topology changes on FCM zonal configuration and requirements, identifying emerging issues that may require changes in zonal configuration, identifying effective solutions to local security and reliability needs, and developing projections of zonal configurations under alternate expansion strategies.*

The LSR and MCL values are included in Exhibit F-17 for the first four capacity commitment periods; only the FCA #4 values for the LSR were calculated using "the higher of" methodology.[79] The Boston and Connecticut LSR has increased by 1,000 MW or more in four years, underlining the potential need for more deliverability and/or resources into these areas.

Exhibit F-17
LSRs and MCLs for the First Four FCAs[(a)]

Capacity Commitment Period		LSR (MW)		MCL (MW)
		CT	NEMA/Boston	Maine
2010/2011	FCA #1	6,496	1,838	3,697
2011/2012	FCA #2	5,666	1,956	3,140
2012/2013	FCA #3	6,640	2,019	3,257
2013/2014	FCA #4	7,419	2,957	3,187

(a) Sources: "Summary of ICR, LSR, and MCL for FCM and the Transition Period," available at http://www.iso-ne.com/markets/othrmkts_data/fcm/doc/summary_of_icr_values.xls. ARA values were used for the 2010/2011 and 2011/2012 capacity commitment periods.

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 37.

V.6 Out-of-Market (OOM) Resources

Out-of-Market (OOM) capacity is a resource that receives revenues from outside the ISO-NE markets. Because OOM resources receive "out-of-market" revenue, these resources can be offered into the FCA at very low bids that do not reflect a market-based or competitive cost of entry. This issue is significant due to recent changes in the rules and the potential that NTAs could be considered OOM. Note that transmission cannot be considered OOM.

In its April 2011 decision, FERC required that OOM resources enter the supply stack at a "benchmark price" determined by ISO-NE. Benchmark Offers will be calculated by resource type for different types of generation and demand resources. The benchmark price is expected to be very similar to the Cost of New Entry (CONE). As discussed, this is an important change since it mitigates the impact of a new resource on the capacity price if the resource is declared OOM. The on-going process is addressing such issues as how long the price floor should be maintained.

According to the ISO-NE Internal Market Monitor (IMM) the amount of OOM capacity procured in the first three auctions are 40 MW, 1,268 MW and 695 MW for FCA-1, FCA-2 and FCA-3, with a total OOM capacity of 2,003 MW, of which 1,733 MW reflects generation resources and

[79] The capacity commitment period requirements for 2010/2011 to 2013/2014 are available in the FERC filings at http://www.iso-ne.com/regulatory/ferc/filings/2008/sep/er08-1512-000_9-9-08_2011-2012_icr_filing.pdf; http://www.iso-ne.com/regulatory/ferc/filings/2009/jan/er09-640-000_1-30-09_icr_filing.pdf; http://www.iso-ne.com/regulatory/ferc/filings/2009/jul/er09-___-000_7-7-09_2012-2013_icr_values.pdf; and http://www.iso-ne.com/regulatory/ferc/filings/2010/may/er10-___-000_05-04-10_icr_2013-2014.pdf. FERC has approved the actual values.

270 MW reflects DSM. Connecticut peakers and Kleen Energy plants are a large portion of the total OOM capacity. Levels of OOM for FCA-4 on a cumulative basis were not significantly higher.

ISO-NE will not carry forward any OOM Capacity from FCA #1 – FCA #3, i.e., they are "grandfathered". Thus, these resources will not be required to bid benchmark prices.

VI. Summary of Key Recent Changes in ISO-NE FCM

Changes in the FCM rules are designed to enhance market signals and give market responses every opportunity to resolve transmission problems. However, in some past situations, the decision to contract with a new resource was based on an explicit calculation of ratepayer benefits that included the effect of the contracted resource on FCM prices. New rules decrease the potential to achieve the calculated benefits from contracting for new resources making NTAs less economic than they would be under past approaches. The new rules also increase the potential for capacity price volatility, retirements, and zonal price separation.

VI.1 Scope of Activity

In February 2010, ISO-NE filed proposed changes to the FCM rules. In an April 23, 2010 order FERC found certain aspects of the proposed rule just and reasonable, but set many issues for a paper hearing. On April 13, 2011, FERC issued its ruling on ISO-NE's changes. Implementation of these changes is on-going as described in a May 13, 2011 letter to FERC from ISO-NE. The current ISO-NE schedule contemplates completion by early 2013 in time for FCA #8, with a chance of implementation by FCA #7; to do so ISO-NE needs to finish implementation by the resource qualification deadline of June 2012. In the interim, NTAs would have to comply with rules related to permissible bidding adopted in 2010 known as Alternative Price Rules 1-3.

VI.2 Description of Changes

The key changes in FCM are designed to enhance market price signals, but have other effects relevant to transmission and NTA options.

- **Buy-Side Market Power Protections** – FCM rules will contain much stronger protections against buy-side market power than in the past. These new rules decrease the ability of NTAs to decrease capacity prices compared to past FCM rules. In some recent situations, contracts were entered into after analysis showed that the resource would likely lower the capacity market price by enabling bids that were below the competitive cost of new entry. Thus, under this prior approach, decisions reflected the conclusion that in exchange for the cost and risk of a CFD for a new unit, the capacity price for the entire load in a zone could potentially be decreased. Under the new FCM rules, the market monitor will require that new units bid at a benchmark price approximately equal to the costs of the power plants assuming no non-market revenues or support. These changes will generally make NTAs less economically attractive than in the past, and therefore, more difficult to implement. This in turn will place more emphasis on transmission options.

- **Elimination of Price Floors and Retirements** – Partly in response to past OOM resources, ISO-NE has had a FCM price floor in all auctions. FERC is requiring the eventual elimination of the floor. Power plant retirements will be encouraged by the elimination of the FCM price floor.

- **Zonal Markets** – New ISO-NE rules emphasizing market price signals at the zonal level increase the likelihood of zonal market price separation. As FERC put it, it wants ISO-NE to model "all zones all the time". ISO-NE is contemplating expanding the number of capacity zones from three zones to all eight load zones.

- **Local Supply Minimums** – New ISO-NE rules increase the minimum local supply level via the introduction of Transmission Security Analysis (TSA) into the determination of the need for local capacity in the FCM is discussed above. Minimum zonal local supply will be based on the greater of the previous approach and the results of TSA analysis[80] in which: (1) load will be based on a 90/10 assessment of demand, (2) local supply including demand side resources will be based on de-rates for potential lack of availability, (3) a load flow analysis will be the basis for determining local supply requirements, and (4) the load flow analysis will reflect two most pressing contingencies involving generation and transmission. Consider the following example. The total resources required in the zone under the TSA after contingencies and at 90/10 load is 10 MW. If after two contingencies, the maximum import is 5 MW; 5 MW must be sourced locally. This is more stressful than the previous FCM market structure under which the minimum local supply was based on 50/50 demand forecasting, installed capacity without demand side de-rates, and a zonal analysis without a load flow analysis.

- **Retirements and FCA** – Power plants can now more readily retire, i.e., there is greater opportunity for retirements or delists to be accepted. For example, if before the auction, the zone's supply exceeds demand, ISO-NE did not model the zone, and hence, no retirements could occur in response to the lowering of the price during the auction. Now ISO-NE will model all zones all the time and allow retirements in response to price during the auction.

VII. ISO-NE Electrical Energy Market

The goals of this section are twofold. First, this section provides a brief description of the interaction between transmission constraints and locational marginal pricing. Second, this section discusses the interactions of transmission option and NTAs with the energy market.

Electrical energy sales are the primary source of revenue for supply side resources. Payments for a new gas-fired combined cycle under a CFD would vary with energy market conditions. These conditions are volatile due to the reliance on natural gas.

In addition, due to the use of nodal or locational marginal pricing, transmission options and NTAs can affect local pricing conditions in the electrical energy market. However, in contrast to resources bid into the FCM, there is no special mitigation required.

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[80] *Tighter of TSA and LSR*

VII.1 Background

On May 1, 1999, ISO-NE began to administer the wholesale electricity marketplace for the region. At the time, there was a single hourly price for all of ISO-NE – i.e., there were no locational price differences. Since March 1, 2003, the New England ISO-NE has been pricing energy using a locational marginal pricing (LMP) scheme similar to the pricing schemes used in New York, PJM, MISO-NEMISO, and recently in California markets.

Three important features of New England's market structure are: (1) bid-based access to electricity transmission which avoids preference based on non-price consideration; (2) close monitoring of pricing for market power abuses; and (3) an industry pool which clears the market and maintains itself as a credit-worthy counter party for all sellers, which promotes liquidity.

VII.2 Market Structure – Locational Marginal Pricing and Transmission

As noted, ISO-NE uses locational marginal pricing, which is a way for electric energy prices to reflect the variations in supply, demand, and transmission system limitations effectively at every location where electric energy enters or exits the wholesale network. In New England, wholesale electricity prices are set at approximately 900 pricing points (i.e., *pnodes*) on the power grid. *Locational marginal prices* (LMPs) differ among these locations as a result of each location's marginal cost of congestion and marginal cost of line losses.

The congestion cost component of an LMP arises because of transmission system constraints that limit the flow of the least-cost generation, which results in the need to dispatch more costly generation. Line losses are caused by physical resistance in the transmission system as electricity travels through transformers, reactors, and other types of equipment, which produces heat and results in less power being withdrawn from the system than was injected. Line losses and their associated marginal costs are inherent to transmission lines and other grid infrastructure as electric energy flows from generators to loads. As with the marginal cost of congestion, the marginal cost of losses affects the amount of generation that must be dispatched. The ISO-NE operates the system to minimize total system costs, while recognizing physical limitations of the system. If the system were entirely unconstrained and had no losses, all LMPs would be the same, reflecting only the cost of serving the next megawatt increment of load by the generator with the lowest-cost electric energy available, which would be able to flow to any point on the transmission system.

The ISO-NE energy market establishes market-clearing prices on a five-minute basis for all locations on the electricity grid. Zonal prices are calculated for the Day-Ahead and Real-Time markets using a load-weighted average of the LMPs at the nodes within each Load Zone. High demand areas that incur significant transmission losses or that cannot import sufficient capacity to serve demand, experience higher LMPs. Higher LMPs signal potential investors that investment is needed in these locations.

Prices are bid-based and reflect the costs of the marginal energy bid on the grid plus congestion charges (positive or negative) and losses. Bids are capped at $1,000/MWh and are subject to review by ISO-NE's Market Monitoring Unit (MMU) for significant deviations from actual marginal costs. In addition, bidders are subject to FERC anti-market manipulation rules.

VII.3 Mass Hub

To help market participants hedge their exposure to risk in the real-time market, when electricity must be physically delivered, ISO-NE provides prices for one Hub, the MASS-Hub, known also as Massachusetts Hub or ISO-NE New England Internal Hub. The ISO-NE's hub comprises 36 nodes in central Massachusetts and is the most commonly used location in the six-state region for bilateral trading. This Hub price is frequently supplemented with over the counter basis prices for forward trading, especially in the prompt year or years, that is, the next 12 months or next few years.

VII.4 Price Determination and ISO-NE Supply

Electrical energy prices are heavily influenced by the capacity and generation mix because the mix and its associated short run operating costs effectively determine the marginal source of supply in each hour.

The ISO-NE supply is more natural gas oriented than the U.S. average. Thus, electrical energy prices will reflect the volatility of natural gas prices.

Most recent additions have been gas-fired, nearly all of which used combined cycle technology. Thus, the search for supply and combo NTAs focused on gas combined cycles. The focus on gas has raised concerns that gas deliverability problems into ISO-NE could create reliability problems.

Exhibit F-18 depicts New England's generation capacity mix by primary fuel type and percentage. 65 percent of supply is either oil- or gas-fired. On the basis of the ISO's 2010 CELT Report, the total 2010 summer installed capacity was forecast to be 31,965 MW with the following fuel mix:[81]

- Fossil-fuel-based generation (22,803 MW) accounts for 71.3% of the installed capacity within the region.
- Natural-gas-fired generation represents the largest component of total installed capacity at 41.2% (13,181 MW).
- Oil-fired generation is second at 21.5% (6,866 MW).
- Nuclear generation is third at 14.5% (4,629 MW).
- Coal-fired generation is fourth at 8.6% (2,756 MW).
- Hydroelectric capacity (1,712 MW) and pumped-storage capacity (1,679 MW) are at 5.4% and 5.2%, respectively.
- Other renewable resources are at 3.6% (1,142 MW).[82]

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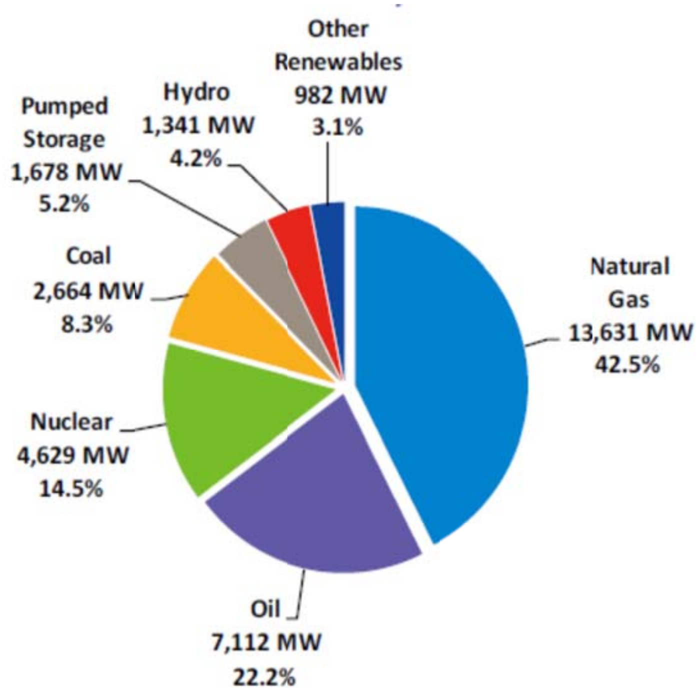
[81] *All the ISO's CELT reports are available at http://www.iso-ne.com/trans/celt/index.html. The summer installed capacity total includes existing generation and expected generation capacity additions but not Hydro-Québec Interconnection Capability Credits (HQICC), demand-response resources, or external purchases and sales. The 2010 CELT Report, Section 2.1, "Generator List with Existing and Expected Seasonal Claimed Capability (SCC)," contains details on 2010 summer installed capacity.*

[82] *The renewable resource fuel sources include landfill gas, other biomass gas, refuse (municipal solid waste), wood and wood-waste solids, wind, solar, black liquor, and tire-derived fuels.*

Exhibit F-18
Generation Capacity Mix by Primary Fuel Type, 2011 Summer Ratings (MW and %)



NOTE: The "Other Renewables" category of fuel sources includes landfill gas, other biomass gas, refuse (municipal solid waste), wood and wood-waste solids, wind, solar, black liquor, and tire-derived fuels. *Black liquor* is the spent cooking liquor that results from the process of converting wood to wood pulp to free the cellulose fibers.

Only Western Massachusetts, Vermont and New Hampshire have capacity mixes with a composition of less than 50 percent gas-fired units. Western Massachusetts is 50 percent hydro (most of which is pump storage), 45 percent gas-fired, and coal the balance. Vermont has a very dissimilar capacity mix among the regions with approximately 85 percent of the capacity mix being hydro or nuclear. New Hampshire also has a large amount of nuclear and hydro at roughly 40 percent of the total mix.

VII.5 ISO-NE versus U.S. Capacity Mix

Exhibit F-19 compares New England's generation capacity mix by fuel type to that of the nation's. ISO-NE's share of oil and gas is higher than the U.S. average and its coal share is lower.

Exhibit F-19
New England's Generation Capacity Mix by Fuel Type Compared with the Nationwide Capacity Mix (%)[(a)]

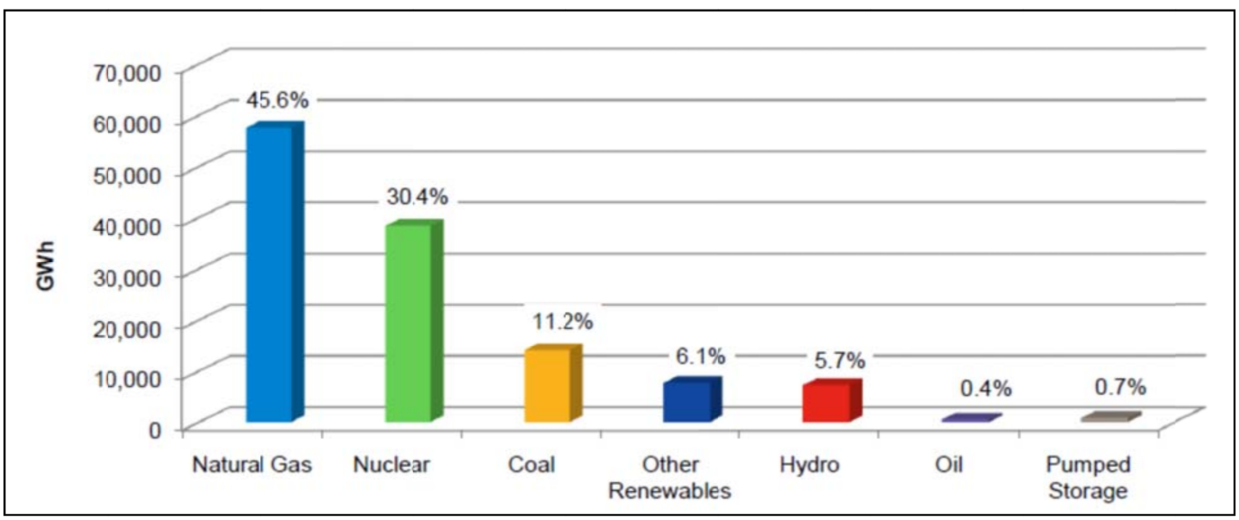
Fuel	New England	United States
Coal	8.3	30.6
Natural gas	42.5	41.5
Oil (heavy and light)	22.2	5.9
Nuclear	14.5	9.6
Hydroelectric, pumped-storage, and other renewables	12.5	12.2

(a) National figures are from the Energy Information Association (EIA). The raw data are available at http://www.eia.doe.gov/cneaf/electricity/page/capacity/capacity.html.

VII.6 ISO-NE Generation

Exhibit F-20 shows the production of electric energy by fuel type for 2011. As shown, natural gas, and nuclear produced the majority of the region's electricity. In total, fossil fuels were used for generating approximately 55% of the electric energy produced within New England in 2011. Natural gas generation produced the highest amount at 50,650 gigawatt-hours (GWh) at 42.4%. In 2009, New England imported 15,226 GWh of electric energy and exported 5,863 GWh of electric energy, which resulted in net imports of 9,363 GWh.

Exhibit F-20
New England Electric Energy Production in 2011, by Fuel Type



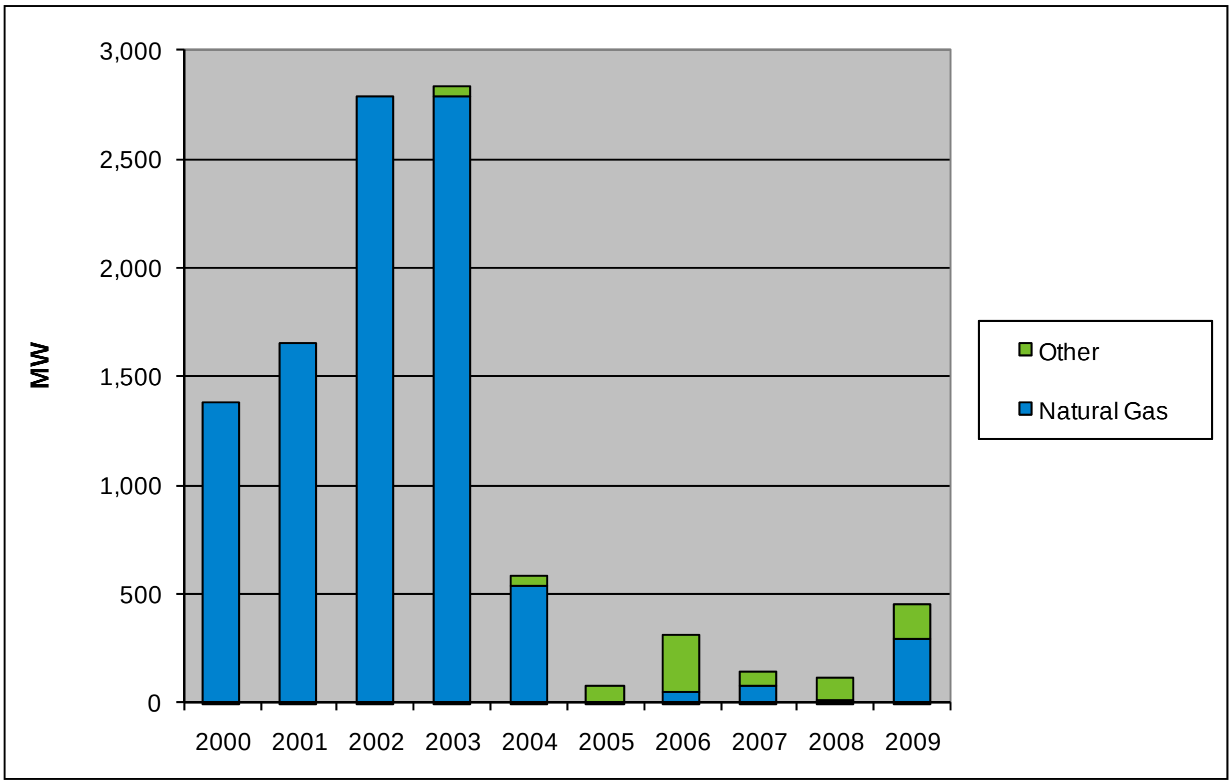
NOTES: The "Other Renewables" category of fuel sources includes landfill gas, other biomass gas, refuse (municipal solid waste), wood and wood-waste solids, wind, solar, black liquor, and tire-derived fuels. The figure excludes 9,377 GWh of net imports.

Fossil fuels produced 55% of the electric energy used in New England in 2009, compared with 69% of the electric energy used in the United States. Nationwide, coal produced 45%, compared with only 12% in New England, and natural gas produced 24% in the U.S., compared with 42% in New England. Additionally, nuclear fuel produced 20% of the nation's electric energy in 2009 compared with 30% in New England. Renewable and hydroelectric resources provided 11% of the country's electric energy in 2009, compared with 13% within the region. Production from petroleum fuels was under 1% both in New England and nationwide.

VII.7 ISO-NE Capacity Additions

There were very few capacity additions in the late-1990s, followed by a large gas-fired expansion starting in 1999 and 2000 in response to capacity shortages as evidenced by declining reserve margins during the later-1990s (see Exhibit F-21).

Exhibit F-21
Recent Generating Capacity Additions – 2000 to 2009



NOTE: The "Other" category includes nuclear uprates, oil-fired generators, and various types of renewable resources. The 2008 value includes 14 MW of gas-fired generation.

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 98.

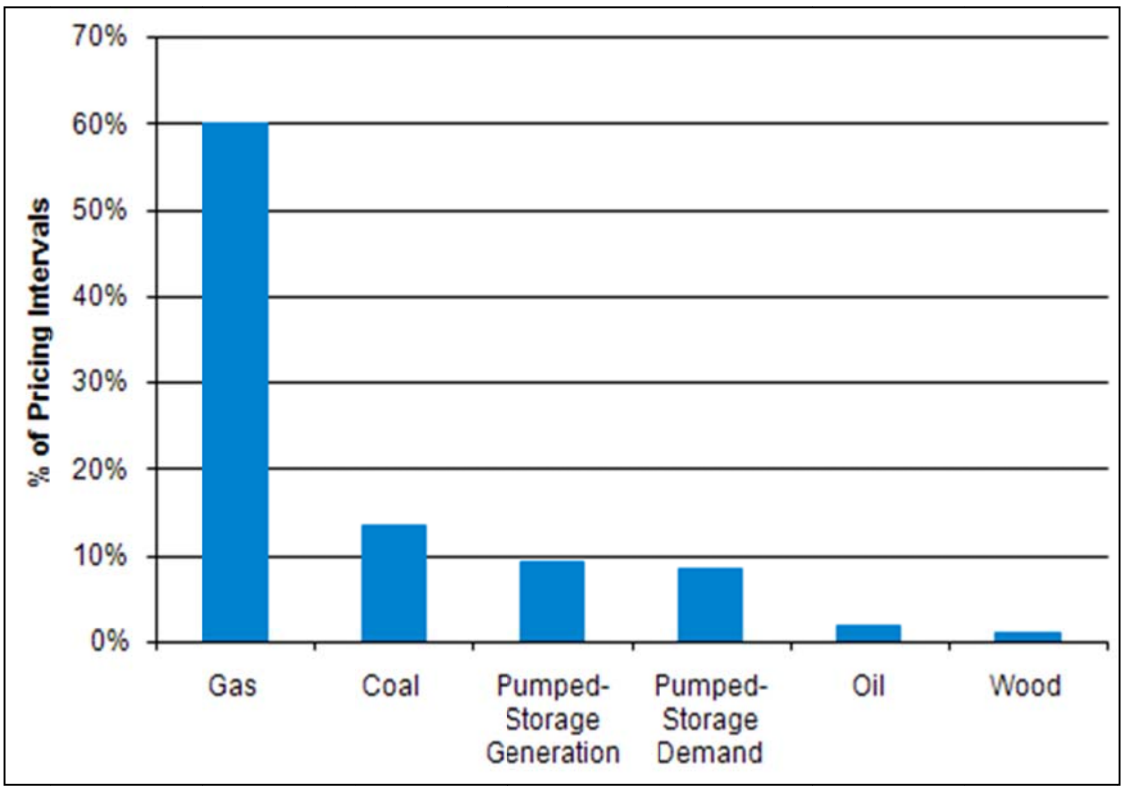
VII.8 Gas Deliverability

Contingencies on the regional gas supply and transmission system could temporarily limit gas deliveries to generators anytime of the year. Also, power plants in the Interconnection Queue may not have adequate gas deliverability and may require upgrades of the gas pipeline system. Further flexibility of operation of gas-fired generating units would assist with the reliable integration of variable-output generation resources, such as wind- and solar-powered facilities. Similarly, a flexible grid can help in this regard by providing a gas by wire option.

VII.9 Price Setting by Hour

In 2008 and 2009, natural gas and/or oil generation set the electrical energy price in New England more than 60% of the time (see Exhibit F-22). Lower demand levels and transmission expansion decreased the amount of oil/gas steam units setting the price from approximately 9% in 2008 to approximately 2% in 2009. In addition, the percent of time coal was setting the price increased (at the expense of gas) from about 10% in 2008 to 17% in 2008. Given the low gas prices in 2009, in some dispatch intervals in September and October 2009, natural gas-fired generation displaced some coal units as base load.

Exhibit F-22
Pricing Intervals as a Percentage of All Pricing Intervals by Marginal Fuel Type, 2009

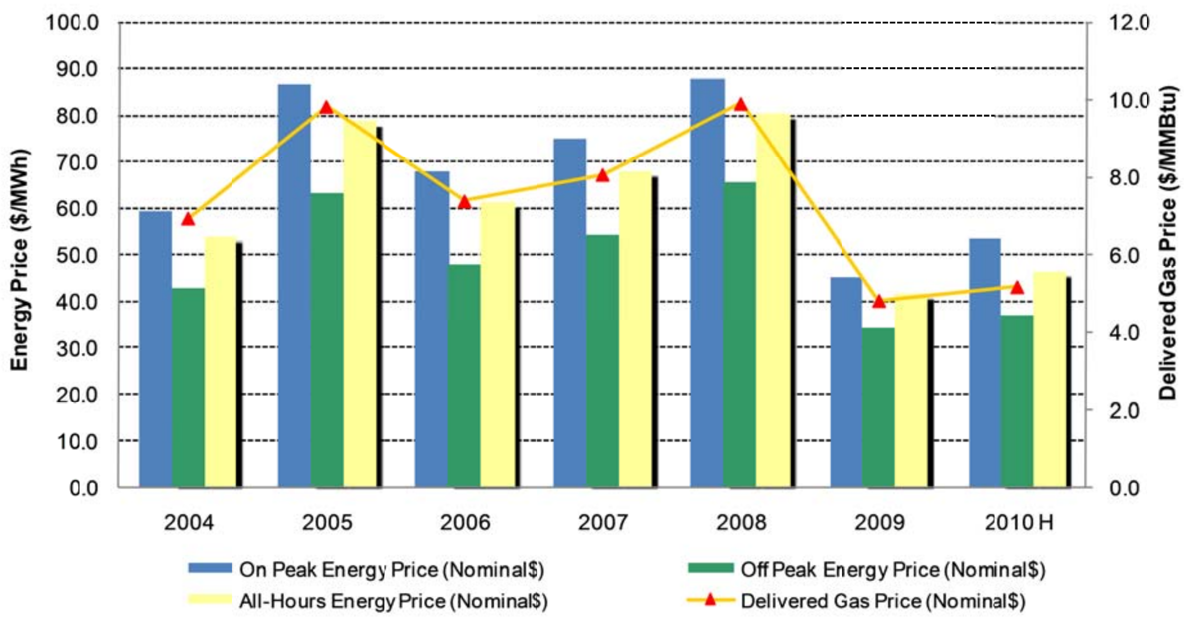


Source: ISO-NE 2008 Annual Markets Report – Same data set is not available in the 2009 Annual Market Report.

VII.10 Electrical Energy Prices and Price Volatility

Electrical energy prices move with natural gas prices, and in large part because gas prices are volatile, electrical energy prices are also volatile. In 2008, energy prices were very high compared to more recent prices, primarily due to high gas and oil prices in that year (see Exhibit F-23). In 2009, wholesale power prices decreased in response to lower natural gas prices, and to a lesser degree lower oil and other fuel prices and lower demand due to the recession. To emphasize, natural gas fueled generation set the energy prices in ISO-NE in most of the hours, and hence, energy price changes are fairly correlated with natural gas price changes. Early 2010 prices showed some recovery from their low levels in 2009 as demand and natural gas prices edged up.

Exhibit F-23
Mass Hub Historical Electrical Energy and Natural Gas Prices



Notes:

(1) Tennessee Zone 6 gas prices have been used as representative of Mass Hub gas prices.

(2) The 2010 hybrid year represents the Oct. 1, 2009 to Sept. 30, 2010 period.

Source: ICF

VIII. ISO-NE Electricity Demand

As electricity demand increases, there is greater potential for stressful events to create over loads – e.g., hot weather combined with contingencies such as the plant or other equipment outages. Hence, ICF's analysis was conducted for the years 2015 and 2020 in part to account for load growth.

VIII.1 Peak Demand

The ISO's all-time actual summer peak demand was 28,130 MW on August 2, 2006, which was due to extreme temperatures and humidity region-wide. In accordance with ISO-NE operating procedures, demand-response programs were activated during this period, which lowered this peak by approximately 640 MW. Without these programs, the peak would have been approximately 28,770 MW. The 2009 summer peak was much lower at about 25,100 MW, primarily because of mild summer weather conditions, and would have been 682 MW higher without demand resources. In 2010, summer peak demand was 27,190 MW.

VIII.2 ISO-NE Demand Forecast

ISO-NE forecasts that summer peak demand will grow from 2010 through 2019 at a rate of 1.4% per year (see Exhibit F-24). This increases demand 3,540 MW cumulatively over the period, or an average of 354 MW per year. Since peak demand leads to resource requirements (ICR) that are approximately 13 percent to 15 percent above peak, this results in an additional requirement of approximately 400 MW per year. This increase in demand is significant because it increases stresses on the transmission grid, all else equal.

ISO-NE's forecast growth rate is a more than one-third reduction in the historical growth rate between 1980 and 2009, i.e., 1.4% per year versus 2.2% per year. Electrical energy demand growth is forecast to be lower than peak at 0.9% per year, versus peak growth of 1.4%. Electrical energy demand growth is also forecast to be slower than in the past. ISO-NE's lower peak and electrical energy demand forecast compared to historical levels reflects slower population and real income growth as well as slower usage growth per household. A return to historical growth patterns, i.e., higher than forecast growth, would increase stress on the transmission system and vice versa.

Exhibit F-24
New England Economic and Demographic Forecast Summary

Factor	1980	2009	CAGR	2010	2019	CAGR
Summer peak (MW)	14,539	27,220	2.2	27,190	30,730	1.4
Net energy for load (1,000 MWh)	82,927	132,045	1.6	131,305	142,520	0.9
Population (thousands)	12,378	14,337	0.5	14,369	14,685	0.2
Real price of electricity (¢/kWh, 1996 $)[(a)]	11.990	11.617	−0.1	11.691	11.484	−0.2
Employment (thousands)	5,485	6,810	0.7	6,718	7,340	1.0
Real income (millions, 2005 $)	281,871	629,265	2.8	627,438	765,697	2.2
Real gross state product (millions, 2000 $)	277,035	626,220	2.9	640,226	841,344	3.1
Energy per household (MWh)	18.954	23.101	0.7	22.944	23.712	0.4
Real income per household (thousands) (2005 base year)	64.425	113.332	2.0	112.680	130.750	1.7

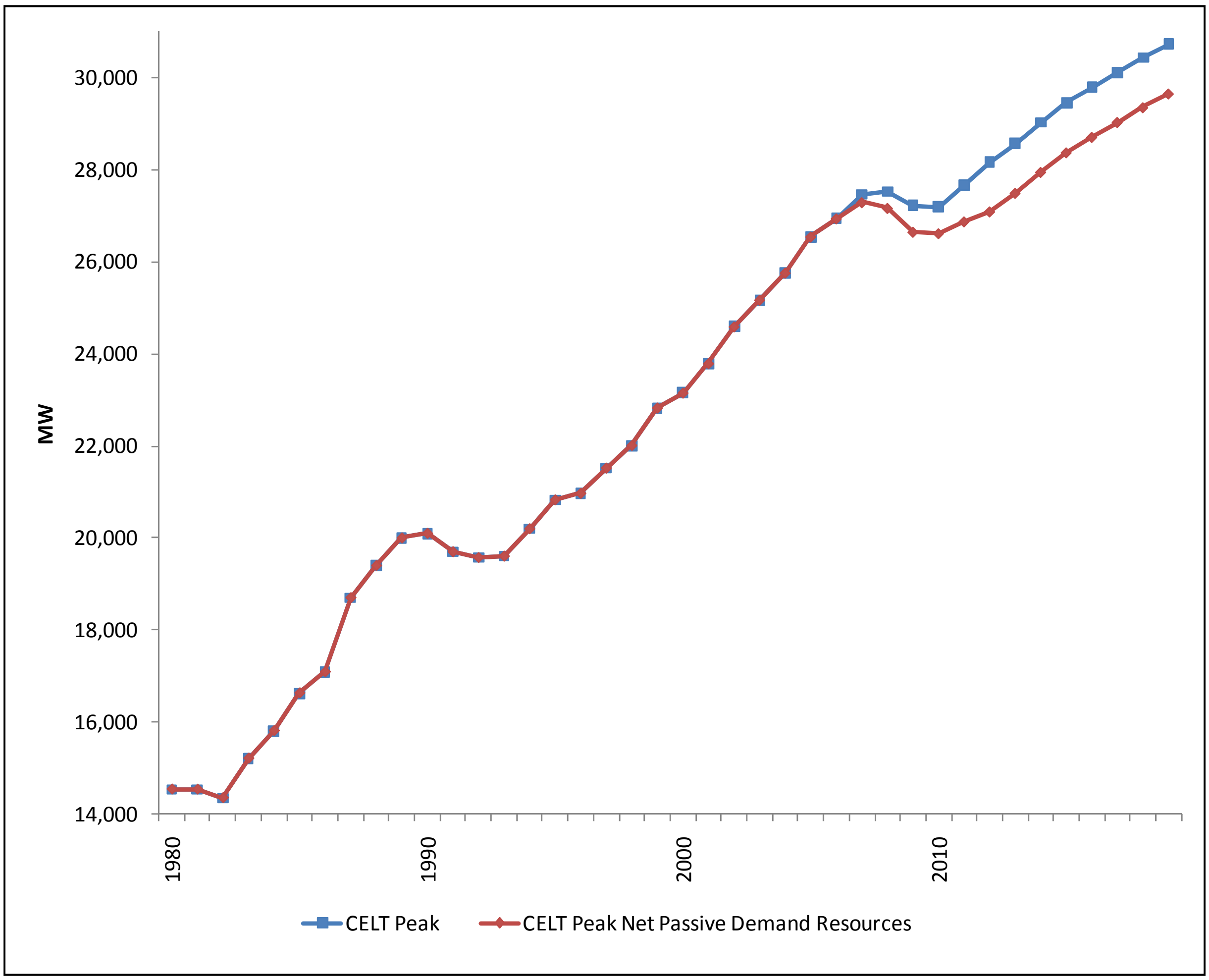
kWh stands for kilowatt-hour.

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 24.

The system-wide load factor (i.e., the ratio of the average hourly load during a year to peak hourly load) declines from 55% in 2010 to 53% in 2019. The decline is attributable to several factors—the increased penetration of cooling load (e.g., air conditioning), which increases the summer peak load; the loss of industry with less variability in its load throughout the year; and the addition of energy-efficient lighting, which decreases load during low-load periods – all of which indicate the less efficient use of electric power system infrastructure.

Within the 1980 to 2010 period, ISO-NE peak demand growth was steady with the exception of dips during some of the past recessions (see Exhibit F-25). Peak demand growth was also strong until the most recent recession. Hence, the ISO-NE forecast also represents a large departure from very recent history.

Exhibit F-25
Historical and Forecast Annual Summer-Peak Loads, 1980 to 2019



NOTE: Additional information is available at "CELT Forecasting Details 2010;" http://www.iso-ne.com/trans/celt/fsct_detail/index.html, and "CELT Report 2010;" http://www.iso-ne.com/trans/celt/report/index.html.

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 31.

Exhibit F-26 highlights that the ten year average growth rate only fell below 2% starting in 2009, in the midst of the recession. This highlights the extent to which the forecast is below recent historical levels.

Exhibit F-26
ISO-NE Peak and Energy Demand Growth Rates: 10-Year Rolling Average

Ten Year Period	ISO-NE	
	Energy	Peak
88-98	0.8%	1.3%
89-99	0.9%	1.3%
90-00	1.3%	1.4%
91-01	1.4%	1.9%
92-02	1.6%	2.3%
93-03	1.6%	2.5%
94-04	1.7%	2.5%
95-05	1.8%	2.4%
96-06	1.5%	2.4%
97-07	1.5%	2.3%
98-08	1.1%	2.1%
99-09	0.6%	1.6%
10 year Rolling Average	1.4%	2.1%

Source: ISO-NE 2010 CELT

Exhibit F-27 highlights that through 2008 ISO-NE peak demand had been growing faster than the U.S. average.

Exhibit F-27
Annual Peak Demand Growth Rates: Comparison of ISO-NE and the U.S.

Year	Contiguous U.S.		ISO-NE	
	Peak Demand	Growth Rate (%)	Peak Demand	Growth Rate (%)
1998	660,293		21,406	
1999	682,122	3.31%	22,607	3.7%
2000	678,413	-0.54%	22,005	1.4%
2001	687,812	1.39%	25,072	2.8%
2002	714,565	3.89%	25,422	3.4%
2003	709,375	-0.73%	24,685	2.4%
2004	704,459	-0.69%	24,116	2.3%
2005	758,876	7.72%	26,885	2.1%
2006	789,475	4.03%	28,130	1.5%
2007	782,227	-0.92%	26,145	1.9%
2008	752,470	-3.80%	26,111	1.1%
Average (1999-2008)		1.4%		2.3%

Sources and Notes:

(1) US Peak Demand represents Contiguous U.S. Non-coincident Peak Load as reported by EIA Table 8.12.

(2) ISO-NE Peak Demand represents Actual Summer Peak as obtained from the ISO-NE 2010 Forecast Data File

The forecasts discussed are for weather normalized demand and are referred to as 50/50 demand. The 90/10 peak demand refers to the demand associated with summer extreme weather that is hot enough that there is only a 10 percent chance that it will be hotter. The 90/10 forecast is approximately 8 percent above the 50/50 peak (see Exhibit F-28).

Southern New England has 80 percent of total ISO-NE peak load, and is forecast to grow at the same rate as the ISO-NE average (see Exhibit F-28).

Exhibit F-28
Summary of Annual and Peak Use of Electric Energy for New England and the States

State[a]	Net Energy for Load (1,000 MWh)			Summer Peak Loads (MW)				
				50/50		90/10		
	2010	2019	CAGR[b]	2010	2019	2010	2019	CAGR[b]
CT	32,675	34,465	0.6	7,240	8,050	7,865	8,760	1.2
ME	11,975	12,975	0.9	2,030	2,315	2,165	2,485	1.5
MA	60,305	66,510	1.1	12,620	14,315	13,555	15,415	1.4
NH	11,620	12,940	1.2	2,410	2,815	2,590	3,040	1.8
RI	8,315	8,845	0.7	1,825	2,045	2,035	2,290	1.3
VT	6,415	6,780	0.6	1,060	1,185	1,100	1,235	1.3
New England	131,305	142,520	0.9	27,190	30,730	29,310	33,225	1.4
CT	32,675	34,465	0.6	7,240	8,050	7,865	8,760	1.2

(a) A variety of factors cause state growth rates to differ from the overall growth rate for New England. For example, New Hampshire has the fastest-growing economy in New England, and Connecticut has the slowest-growing economy in the region.

(b) CAGR stands for compound annual growth rate.

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 23.

VIII.3 ICR and Resulting Local Reserves

Exhibit F-29 summarizes the ISO-NE 50/50 peak load forecast, the net Installed Capacity Requirement (ICR) values for the 2010/2011 through 2013/2014 capacity commitment periods, the representative net ICR values for the 2014/2015 through 2019/2020 periods, and the percentage of the resulting reserves.[83] The net ICR values for the 2010/2011 through 2013/2014 capacity commitment periods, which are calculated as the ICR minus the value of Hydro-Québec Interconnection Capability Credit (HQICC) for the particular capability year, reflect the latest ICR values established for those years. The ICR and HQICC values for the 2010/2011 through 2013/2014 commitment periods have been approved by FERC. The representative net ICR values for 2014/2015 and beyond were calculated by the ISO-NE input using the following assumptions:

- The availability of 1,700 MW of total tie-line benefits from the three neighboring balancing authority areas of Québec, the Canadian Maritime provinces, and New York
- 2010 CELT load forecast
- Generating and demand-resource capability ratings, availability, and performance metrics, based on the values used to calculate the ICR for the fourth FCA (FCA #4) for the 2013/2014 capability period.[84]

As shown in the Exhibit, the Net ICR is forecast to grow at a 1.3% per year growth rate between the level for the period covered by FCA #5, and the 2019/2020 period covering summer 2019. The resulting required reserves range from 13 percent to 15 percent. The reserve levels are important related to the later discussion of demand resources.

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[83] *Resulting reserves are the amount of capacity in excess of the forecast 50/50 peak load. Percent resulting reserves =*

[{(Net ICR − 50/50 peak load) ÷ 50/50 peak load} × 100].

[84] *The ISO-NE submitted the ICR filing to FERC on May 4, 2010; it is available at http://www.iso-ne.com/regulatory/ferc/filings/2010/may/er10-___-000_05-04-10_icr_2013-2014.pdf.*

Exhibit F-29
Actual and Representative Future New England Net Installed Capacity Requirements for 2010–2019 and Resulting Reserves

Year	Forecast 50/50 Peak (MW)	Actual and Representative Future Net ICR[a] (MW)	Resulting Reserves (%)
2010/2011	27,190	31,110[b]	14.4
2011/2012	27,660	31,741[c]	14.8
2012/2013	28,165	31,965[d]	13.5
2013/2014	28,570	32,127[e]	12.5
2014/2015	29,025	32,672[f]	12.6
2015/2016	29,450	33,178[f]	12.7
2016/2017	29,785	33,604[f]	12.8
2017/2018	30,110	34,025[f]	13.0
2018/2019	30,430	34,434[f]	13.2
2019/2020	30,730	34,818[f]	13.3

(a) "Representative Future Net ICR" is the representative ICR for the region, minus the tie-reliability benefits associated with the HQICCs.

(b) The ICR value for 2010/2011 reflects the value for the third Annual Reconfiguration Auction (ARA #3) approved by FERC in its February 12, 2010, Order Accepting ISO-NE New England's Proposed Installed Capacity Requirement, Hydro Québec Interconnection Capability Credits, Related Values, and Tariff Changes, Subject to Condition (http://www.iso-ne.com/regulatory/ferc/orders/2010/feb/er10-438-000_2-12-10_icr_jump_ball_order.pdf).

(c) The ICR value for 2011/2012 reflects the ARA #2 value accepted for filing by FERC in its March 29, 2010, Order Accepting for Filing the Installed Capacity Requirement, Hydro Québec Interconnection Capability Credits and Related Values for the Second Reconfiguration Auction for the 2011/2012 Capability Year (http://www.iso-ne.com/regulatory/ferc/orders/2010/mar/er10-714-000_3-29-10_ltr_order_accept_2011-2012_icr.pdf).

(d) For the 2012/2013 capability year, the net ICR value represents the value approved by FERC in its August 14, 2009, Filing of Installed Capacity Requirement, Hydro-Québec Interconnection Capability Credits and Related Values for the 2012/2013 Capability Year (http://www.iso-ne.com/regulatory/ferc/orders/2009/aug/er09-1415-000_8-14-09_accept%202012-2013%20icr.pdf).

(e) For the 2013/2014 capacity commitment period, the net ICR value represents the value filed with FERC on May 4, 2010. Representative net ICR values are presented for the 2014/2015 through 2019/2020 capability years, reflecting the amount of capacity resources needed to meet the resource adequacy planning criterion.

(f) The 2014/2015 through 2019/2020 capability years' representative net ICR values reflects the amount of capacity resources needed to meet the resource adequacy planning criterion.

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 35

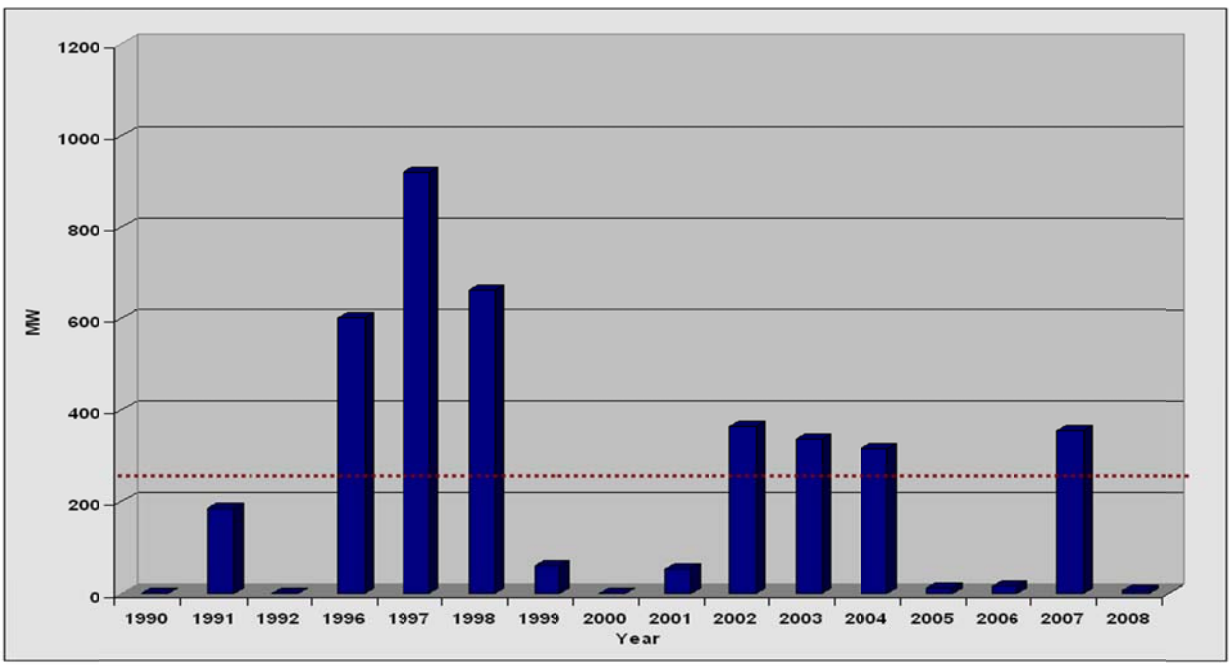
IX. Power Plant Retirements

Power plant retirements create new flow patterns on the grid unless replaced by an extremely similar unit, which is unlikely. Power plant retirements could increase when the FCM capacity price floor is lifted and due to new environmental regulations. The owners of Salem Harbor 1-4 have recently filed for retirement on a non-price basis. ISO-NE does not consider it appropriate to rely on Vermont Yankee in long-term studies due to its potential retirement. While the focus here is on supply retirements, demand resources are contracted one year at a time and can return to service with little future penalty relative to never having participated as a demand resource. Thus, rapid changes in the resource situation involving supply and demand resources are possible once the FCM price floor is lifted and once new environmental controls are required.

IX.1 Historical

Between 1996 and 2008, 3,683 MW of capacity in New England retired (see Exhibit F-30). The following exhibit shows power plant retirements which include the loss of major nuclear units as well as older fossil units.

Exhibit F-30
ISO-NE Capacity Retirements, 1990–2008



Source and Notes: ISO-NE Seasonal Claimed Capability (SCC) Report, February 1, 2009, and SNL for all unit types except nuclear. Nuclear plant shutdown dates from EIA (available at http://www.eia.doe.gov/cneaf/nuclear/page/nuc_reactors/shutdown.html)

Between 1991 and 2008, ISO-NE retirements have averaged over 216 MW per year. Currently, there are still approximately 7,000 MW of conventional oil and gas steam capacity remaining in the system. Additionally, there are old peaking combustion turbines remaining in the system. 30 percent of capacity is 41 years to 60 years old or older (see Exhibit F-31).

Older steam plants are candidates for retirement. There is also significant coal capacity at risk due to recent developments in environmental regulations, such as the Cross State Air Pollution Rule (CATR), the Hazardous Air Pollution Rule (HAPs), Regional Greenhouse Gas Initiative (RGGI), coal combustion residue restrictions, Once Through Cooling (OTC) regulations and possible national carbon emission regulation. National CO_2 program options range from administrative action to a cap and trade program which is more stringent and broad based geographically than RGGI.

By 2020, 5,138 MW of fossil capacity in ISO-NE will be 50 years old or older (see Exhibit F-31), and may be candidates for retirement. As noted, this is especially true for legacy oil and gas steam units which use older technology, and hence, are less efficient and higher emitting. The CPUC has endorsed an assumption of retirement after 50 years of service for fossil fueled plants in estimating future resource needs.[85] Also, the average fossil age of retired plants retirement in the U.S. was 36 years of age and 39 in ISO-NE. This is another indicator that plant lifetimes are limited, especially for older oil and gas plants using older technology.

Exhibit F-31
New England's 2010 Summer Generation Capacity Mix by Fuel Type and In-Service Dates[a, b, c]

Fuel Type	In-Service Date Before 1950		In-Service Date 1951–1970		In-Service Date 1971–1990		In-Service Date 1991–2000		In-Service Date 2001 and after		Total	
	# of Assets	MW	# of Assets	MW	# of Assets	MW	# of Assets	MW	# of Assets	MW	MW	%
Gas	5	73	0	0	12	1,617	20	3,564	38	7,928	13,181	41.2
Oil	3	10	61	2,485	25	4,014	11	146	21	212	6,866	21.5
Nuclear	0	0	0	0	5	4,629	0	0	0	0	4,629	14.5
Coal	0	0	13	2,570	2	186	0	0	0	0	2,756	8.6
Pumped storage	1	29	0	0	6	1,649	0	0	0	0	1,679	5.2
Hydro	68	774	8	328	160	434	32	23	31	153	1,712	5.4
Other renewables	0	0	1	43	33	633	28	215	58	251	1,142	3.6
Totals	77	887	83	5,426	243	13,162	91	3,948	148	8,543	31,965	100.0
Percentage of total MW		2.8%		17.0%		41.2%		12.3%		26.7%		

(a) Generator assets in this table may be power plants or individual units that make up power plants. Values do not include HQICC, demand resources, or external purchases and sales.

(b) A total of 10,011 MW of new generation has been installed since the start of the markets in May 1999. This total is based on the claimed capability of these assets as of March 2, 2010, and projected capabilities of assets expected to be in service by summer 2010.

(c) Totals may not equal sum because of rounding.

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 102

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[85] In the recent Connecticut DPUC decision pertaining to the 2008 Connecticut Integrated Resource Plan Docket No. 08-07-01 dated February 18th, 2009 the DPUC stated that "The Department (DPUC) believes that a conservative generator retirement projection would include nine units totaling 929 MW during the planning period 2011-2018. After 2011, all units reaching 50 years of operation would retire during their 50th year of operation".

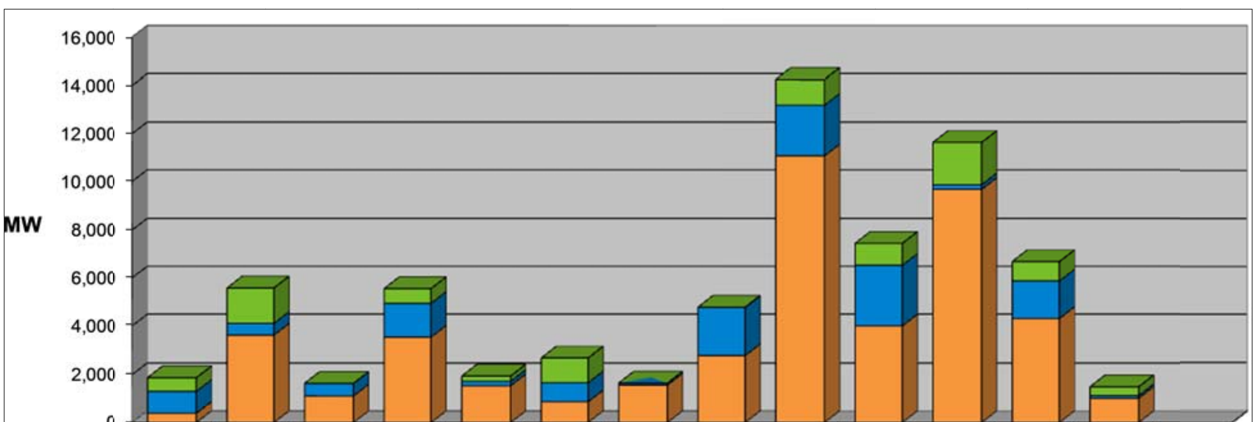
X. Potential Generation Resource Additions

The search for NTA supply was based on resources in the ISO-NE Interconnection Queue. Neither a supply nor a combo NTA was found. This reflects that the actual potential additions of resources reflect many factors and may not always be optimally sited from the perspective of minimizing stress on the transmission grid. Hence, delivery capability across sub-regions can be important.

X.1 Generating Units in the ISO-NE Generator Interconnection Queue

The interconnection requests in the ISO's Generator Interconnection Queue reflect the region's interest in building new generation capacity. Exhibit F-32 shows the capacity of the 84 active generation-interconnection requests in the queue by RSP subarea as of April 1, 2010. The four areas with the most proposed capacity additions are in the SEMA, WMA, CT, and ME subareas. Together, these subareas have about 5,321 MW under development out of a total of 8,809 MW of active projects for New England. A total of 2,937 MW is proposed for the three sub-areas in Connecticut.

Exhibit F-32
Capacity of Generation-Interconnection Requests by RSP Sub-Area



	BHE	ME	SME	NH	VT	WMA	CMA	BOST	SEMA	RI	CT	SWCT	NOR	Total
Active	564	1,463	2	612	215	1,030	0	13	1,056	912	1,767	810	360	8,809
Commercial	917	487	520	1,405	186	789	81	1,971	2,117	2,530	192	1,565	111	12,871
Withdrawn	388	3,616	1,113	3,531	1,536	872	1,564	2,791	11,069	3,997	9,668	4,302	1,021	45,467

NOTES**:** All capacities are based on the projects in the ISO-NE Generator Interconnection Queue as of April 1, 2010, that would interconnect with the ISO-NE system. Projects involving only transmission or that did not increase an existing generator's capacity were excluded. Projects with more than one listing in the queue, representing different interconnection configurations, were only counted once.

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 48

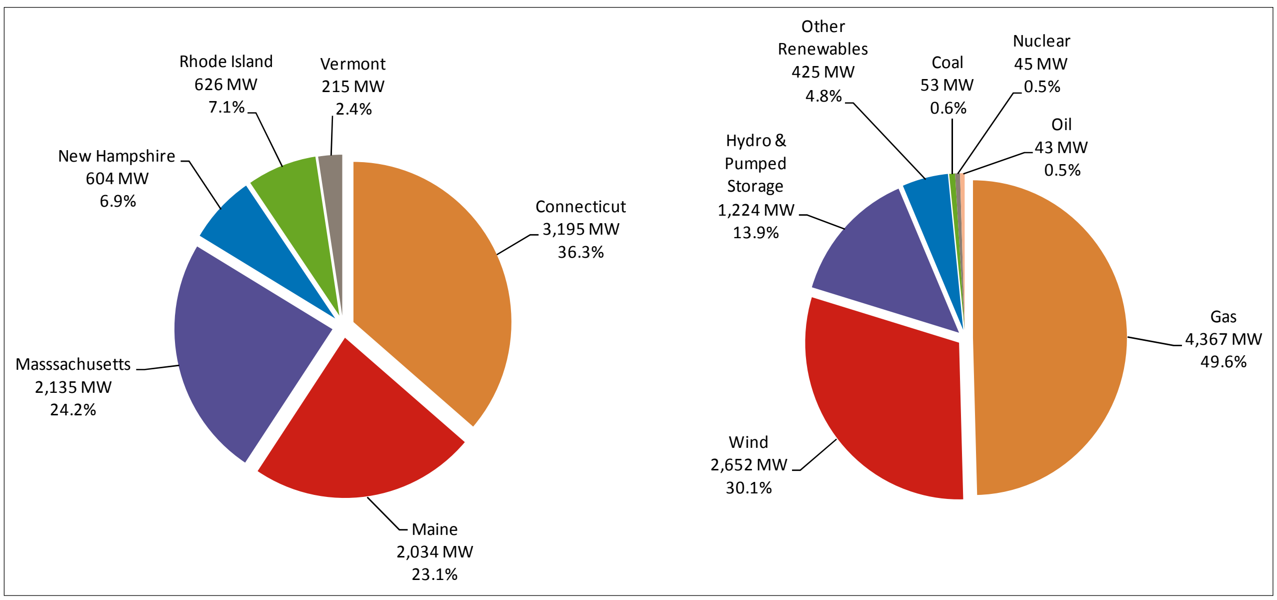
A summary of the projects in the queue as of April 1, 2010, is shown in Exhibit F-33. Since the first publication of the Generator Interconnection Queue in November 1997, 64 generating projects (12,871 MW) out of 300 total generator applications (totaling 67,147 MW) have become commercial, i.e., approximately 20 percent.[86] Since the queue's inception, proposed projects totaling approximately 45,467 MW have been withdrawn, reflecting a megawatt attrition rate of 68%. The 84 active projects in the queue total 8,809 MW. Exhibit F-34 shows the resources in the ISO-NE Generator Interconnection Queue, by state and fuel type, as of April 1, 2010.

Exhibit F-33
Summary of Queue Projects as of April 1, 2010

Category of Projects	Projects	Total Capacity (MW)
Commercial	64	12,871
Active	84	8,809
Withdrawn	152	45,467
Total	**300**	**67,147**

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 49

Exhibit F-34
Resources in the ISO-NE Generator Interconnection Queue, by state and fuel type, as of April 1, 2010 (MW and %)



NOTES: The total for the State of Connecticut (3,195 MW) is greater than the total for the subareas, CT, SWCT, and NOR (2,937 MW because the area of the state is greater than the total area used for the subareas. The "Other Renewables" category includes wood, refuse, landfill gas (LFG), other bio gas, and fuel cells. A total of 38 MW of hydro is included in the 1,224 MW total of hydro and pumped storage. The totals for all categories reflect all queue projects that would interconnect with the system and not all projects in New England.

Source: Taken from ISO New England 2010 Regional System Plan, October 28, 2010, page 49

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[86] *The projects that have been proposed but discontinued faced problems during their development associated with financing, licensing, insufficient market incentives, or other issues. More information on interconnection projects is available at "Interconnection Status" (April 1, 2010); http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/status/index.html.*

XI. Demand Resources

The search for NTA demand resources was based on aggressive demand side assumptions. However, even with aggressive assumptions, no demand side or combo NTA was found. In addition, ISO-NE is already heavily reliant on demand side resources even without expanding this reliance via a demand side NTA. In FCA #5, demand side resources were 3,590 MW. Under the aggressive demand side assumptions used in the NTA search, by 2020, the quantity of passive resources increases from approximately 1,100 MW to 2,400 MW to 2,800 MW. One issue raised by this reliance is whether "fatigue" or attrition of demand resources would occur in the future.

XI.1 Types of Demand Resources

June 1, 2010, marked the beginning of the first FCM capacity commitment period. Two categories of FCM demand resources exist—passive and active demand:

- **Passive Resources** (e.g., energy efficiency) are principally designed to save electric energy (MWh). The electric energy that passive projects save during peak hours also helps to fulfill the ICR. These projects are in place at all times and do not reduce load based on real-time system conditions or ISO-NE instructions. The FCM includes two types of passive projects:
  - **On Peak** – passive, non-weather-sensitive loads, such as efficient lighting.
  - **Seasonal Peak** – passive, weather-sensitive loads, such as efficient heating and air conditioning (HVAC).
- **Active Resources** (e.g., demand response) are designed to reduce peak loads in electric energy use and are considered capacity resources (MW). These resources can reduce load based on real-time system conditions or ISO-NE instructions. The FCM includes two types of active projects:
  - **Real-time Demand Response** – Active, individual resources, such as active load management and distributed generation at commercial and industrial facilities.
  - **Real-Time Emergency Generation** – Active, emergency distributed generation.[87]

XI.2 Quantity

Demand side resources expanded considerably (+52%) between FCA #1 and FCA #5 (see Exhibit F-35). This was in addition to the increase in demand resources in FCA #1 relative to earlier periods. In FCA #1, they were 6.7% of the total capacity acquired, and by FCA #5, demand resources were 9.4%. In contrast, between FCA #1 and FCA #5, generation has grown only 2%, even with Connecticut gas power plant additions.

If all the excess capacity were removed (e.g., retired quickly due to elimination of the FCM price floor), and this was exclusively a decrease in generation supply, then demand resources would

[87] *Real-time emergency generators are required to begin operating within 30 minutes, which results in increasing supply on the New England grid, and also to continue that operation until receiving a dispatch instruction allowing them to shut down.*

account for 10.4% of capacity and 80% of local reserves. This scenario could occur as evidenced by the loss of Salem Harbor and the potential loss of Vermont Yankee.

Exhibit F-35
Results of the First Five Forward Capacity Auctions

Auction[1]	Cleared Generation (MW)	Cleared DR[2] (MW)	Total Capacity Acquired (MW)	Capacity Required (MW)	Cleared DR as Share of Total Acquired Capacity (%)
FCA #1 (2010/11)	30,865	2,279	34,077	32,305	6.7
FCA #2 (2011/12)	32,207	2,778	37,283	32,528	7.5
FCA #3 (2012/13)	32,228	2,867	36,996	31,965	7.8
FCA #4 (2013/14)	32,247	3,261	37,501	32,127	8.7
FCA #5 (2014/15) (Initial Results)	31,439	3,468	36,918	33,200	9.4

Only about 60 percent of demand resources are active resources (see Exhibit F-36). Active demand resource totals include a 600 MW cap on real-time emergency generation resources. Power plant retirement scenarios after removal of the price floor imply a huge potential reliance on active demand resources. Southern New England has 77 percent of the active demand resources. (See Exhibit F-37).

Exhibit F-36
DSM Categories Starting in June 2010

Demand Resources Cleared in the FCM to Date						
Resource Type	DR Category	Capacity (MW)				
		FCA #1	FCA #2	FCA #3	FCA #4	FCA #5
On-Peak Demand Resource	Passive	554	709	799	970	1,134
Real-Time Demand Response Resource	Active	864	915	1,194	1,363	1,382
Critical Peak Demand Resource	Active	106	285	--	--	--
Real-Time Emergency Generation Resource	Active	875	759	630	688	772
Seasonal Peak Demand Resource	Passive	146	269	273	328	352
Total		**2,544**	**2,937**	**2,898**	**3,349**	**3,468[1]**

[1] 3,590 MW before 600 MW cap for Real Time Emergency Generation.

Exhibit F-37
Demand-Resource Capacity that Cleared in FCA #3 (MW)[a]

Resource Type	ME	NH	VT	MA	CT	RI	Total
On-peak demand resource	60	63	75	418	114	69	799
Real-time demand-response resource	274	41	33	524	273	49	1,194
Real-time emergency-generation resource[b]	32	11	8	279	194	76	630
Seasonal-peak demand resource	0	0	0	21	251	2	273
Total	**366**	**116**	**116**	**1,256**	**841**	**200**	**2,897**

(a) All megawatt values include the loss adjustment. Totals may not equal the sum because of rounding.

(b) The use of real-time emergency-generation resources to meet the ICR is limited to 600 MW, but the 600 MW cap has not been applied to the values in this table.

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 42

XI.3 Use of Active DSM

June 24, 2010 was the first time DR was called upon to dispatch in a real-time scenario. While DR resources appear to have performed well for ISO-NE as a whole, underperforming resources were concentrated in high loads centers like eastern MA and CT. Excluding ME, VT, and NH, total New England performance was 78%. Performance was as low as 66% in SEMA (see Exhibit F-38).

Exhibit F-38
DSM Performance Concerns

Demand Response Performance, June 24 2010.

Load Zone	Total Net CSO	Average Aggregate Performance*	Percent
Connecticut	226.83	170	75%
WCMA	79.59	79	99%
NEMA	70.74	46	65%
SEMA	45.23	30	66%
Rhode Island	27.76	27	97%
Vermont	23.71	29	122%
New Hampshire	29.11	33	113%
Maine	166.22	239	144%
New England	**669**	**653**	**98%**

* Preliminary; performance levels measured between 13:50 and 16:24.

Source: ISO-NE 2010 Q2 Quarterly Report

XI.4 DSM "Fatigue"

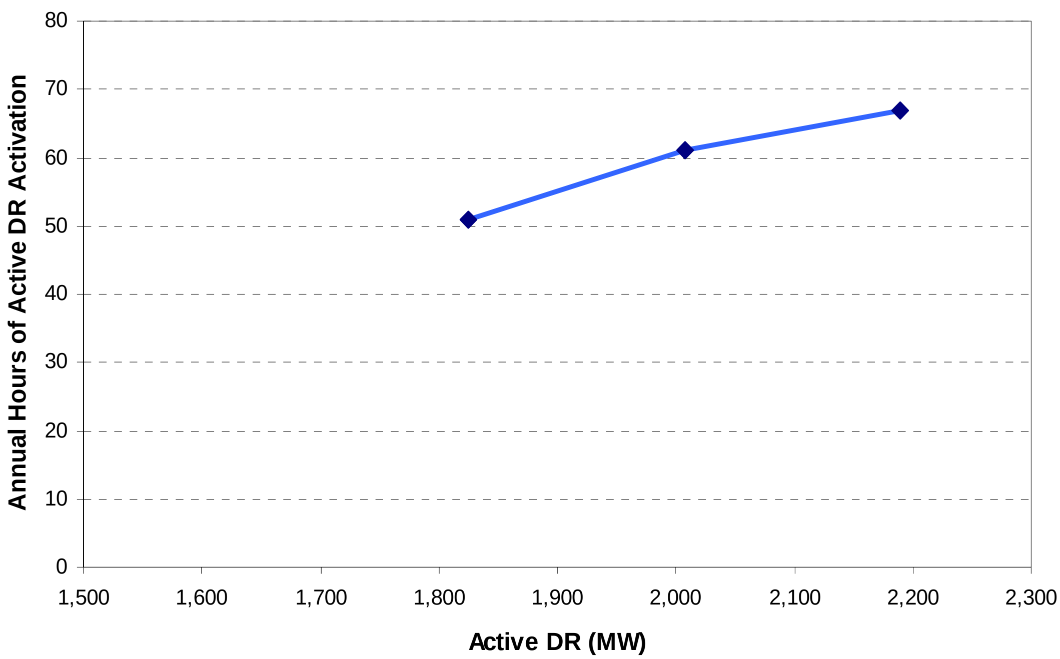
The high contribution of Demand Resources is a big question and concern for some from an overall resource adequacy and reliability planning standpoint. As demand resources grow and displace generation resources, demand reductions will be called to perform in more hours. Given that there is no ISO-NE history of DSM performance under conditions of frequent call, there is a significant question regarding the ability of the resources to perform for an unexpectedly extended period at more frequent rates.

The use of active DSM, especially interruptible load has become increasingly an important issue. PJM has recently changed pricing rules for interruptible load. There is a separate price for load that can only be interrupted up to 60 hours per year (12 episodes of 5 hours), and a higher price for load without such limits (nearly all cleared PJM resources have the 60 hour limit). ISO-NE does not have such a system.

In the past, ISO-NE performed an analysis to determine the demand response operable capacity for FCA#4 (2013/2014 period). In this analysis ISO-NE considered three scenarios for demand resources that will clear in the auction: (1) a Low scenario that assumes that DR resources will be the same as FCA#3, (2) an Intermediate scenario that assumes the DR resources will be ten percent higher relatively to the FCA#3 and (3) a High scenario where DR resources are assumed to be twenty percent higher than FCA#3.

The analysis concluded that in the high scenario which has a total of around 3,500 MW of demand resources and active demand resources of 2,200 MW, the need will be for the resources to perform in more than 67 hours under the 50/50 load growth projection for that resource year (see Exhibit F-39). In the low scenario with approximately 2,900 MW of demand resources and 1,800 MW of active demand resources, the call on the demand side resources is expected to be approximately 50 hours.

Exhibit F-39
Likely Use of FCM DSM (2013/2014 Capacity Period)



Source: Demand Resource Operable Capacity Analysis for the 2013/14 Capability Year

These scenarios reflect not only an increase in the hours of need, but also implicit in this is the fact that the resources would be needed for longer durations under peak conditions, e.g., 90/10 demand.

In spite of current excess capacity, ISO-NE still expects that under 90/10 conditions to require 2,300 MW of supply (see Exhibit F-40). To obtain 2,300 MW of load and capacity relief, ISO-NE system operators would need to implement Actions 1 through 13 of OP 4, which includes accessing active demand resources, a situation discussed further in the demand resource section. This also allows the depletion of the 30-minute and partial depletion of the 10-minute reserve (1,000 MW), scheduling market participants' submitted emergency transactions and arranging emergency purchases between balancing authority areas (1,600 MW–2,000 MW), and implementing 5% voltage reductions (450 MW). This highlights the level of potential reliance on DSM even in the absence of even greater DSM reliance as part of an NTA.

Exhibit F-40
Projected New England Operable Capacity Analysis for Summer 2010 to 2019, Assuming 90/10 Loads (MW)

Capacity Situation (Summer MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Load (90/10 forecast)	29,310	29,835	30,390	30,840	31,340	31,810	32,180	32,545	32,895	33,225
Operating reserves	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Total requirement	31,310	31,835	32,390	32,840	33,340	33,810	34,180	34,545	34,895	35,225
Capacity	31,110	31,741	31,965	32,127	32,672	33,178	33,604	34,025	34,434	34,818
Assumed unavailable capacity	−2,100	−2,100	−2,100	−2,100	−2,100	−2,100	−2,100	−2,100	−2,100	−2,100
Total net capacity	29,010	29,641	29,865	30,027	30,572	31,078	31,504	31,925	32,334	32,718
Operable capacity margin[(a)]	−2,300	−2,194	−2,525	−2,813	−2,768	−2,732	−2,676	−2,620	−2,561	−2,507

(a) "Operable capacity margin" equals "total net capacity" minus "total requirement."

Source: Taken from ISO New England 2010 Regional System Plan, October 28, 2010, page 47

XI.5 ISO-NE Process

To determine whether the expected levels of active demand resources that clear in the initial FCAs could be reliably integrated in New England without having a negative impact on market and system operations, the ISO-NE performed an initial operable capacity analysis of active demand resources. The analysis focused on varying levels of participation by active demand resources during the initial FCM delivery years. This initial analysis showed that the 2010 active-demand-resource levels met the criteria needed for system reliability; however, the analysis of the outcome of FCA #2 for the 2011/2012 delivery year identified operational issues and the potential need to change FCM market rules. Specific concerns were as follows:

- The ability of active demand resources to maintain reduction without fatigue during the anticipated hours of operation (emphasis added)[88]
- Access to the resources outside the initially approved program hours and requirements
- The appropriateness of reserve “gross-up” rules[89]
- Auction transparency during the annual auctions
- Infrastructure and telemetering requirements for the active demand resources.

The ISO-NE led an open stakeholder process that included a review of the operable capacity analysis of active demand resources and revised FCM rules to accommodate these resources. This stakeholder process culminated with unanimous support at the NEPOOL Participants Committee and ultimately a filing with FERC on October 1, 2008, which FERC approved on October 28, 2008.[90] The revised rule included provisions on the following areas of concern:

- The dispatch and settlement rules governing active demand resources
- The eventual elimination of the critical-peak resource category and the conversion of these resources into other categories of demand resources
- Improved information to facilitate active-demand-resource participation in Forward Capacity Auctions
- A clarification of the ISO’s ability to impose appropriate sanctions when market participants with active demand resources do not comply with their obligations (emphasis added).

The ISO-NE processes did not result in direct attention to the fatigue issue and the associated sanctions issues. For example, there was no change similar to the recent PJM rule change discussed above related to demand resources.

XI.6 DSM NTA Risks

The ISO-NE processes notwithstanding, there are demand resource risks, especially for incremental reliance in the context of an NTA. In FCA #5, ISO-NE meets 9.4 percent of its total supply via demand resources. In a power plant retirement scenario, demand resources could end up as 80 percent of reserve requirements. Only 60 percent are even active resources. This is already a large amount. In a case with more power plant retirements or unexpectedly high load growth, the reliance on DSM, including the amount and the hours interruptible load is

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[88] Customers may become fatigued with frequent operation as a demand-response resource and not want to respond when required. For example, a customer in the business of making a product may prefer fulfilling an order rather than repeatedly reducing energy consumption and delaying production.

[89] Gross-up rules give credit for customer actions that both reduce load at the customer’s meter and reduce power system losses.

[90] ISO-NE New England Inc. and New England Power Pool FERC Filing, Tariff Revisions Regarding Elimination of the Reserve Margin Gross-Up for Demand Resources, FERC Docket No. ER09-___-000 (October 31, 2008); http://www.iso-ne.com/regulatory/ferc/filings/2008/oct/er09-209-000_10-31-08_dr_gross-up_filing.pdf.

called upon to accept interruption, could further increase ISO-NE's already high dependence on successful DSM outcomes. Demand side NTAs involve even greater reliance on DSM in spite of the lack of experience with a DSM program of the type already being pursued. ISO-NE could be exposed to significant attrition of demand side resources in the event these resources were extensively and repeatedly called on by ISO-NE to decrease load – e.g., frequently in the summer. Very little data exists on DSM performance under the combination of high demand and very high DSM reliance.

Also, DSM contracting under the FCM is for a single year with only limited penalties for instant return to firm service. Special procedures could be required to make DSM reliable enough for use as an NTA. This could include longer contract periods due to the longer lead time for transmission than generation, greater penalties for non-performance than loss of FCM revenue or a similar amount such as no return to firm service for an extended period of time, remote 2-way access to load to be able to remotely monitor and control load at the source to prevent return to service, and greater evergreen provisions (e.g., when house or business is sold that new owner is required to honor the contract).

The current ISO-NE FCM results could lead to a large majority of ISO-NE reserves being DSM reserves. As noted, this is unprecedented. The closest analog is the experience of Florida Power in the late-1990s.

The ISO-NE market differs from the general approach in Florida which limits reliance on DSM to approximately 45 to 50% of reserves and sets reserve margins of the leading utilities to 20 percent.[91] This guideline was developed after a loss of DSM resources that occurred when shortage hour equivalents reached 45-80 hours in one 12-month period in the late 1990s.[92]

ISO-NE expects the 45 to 80 hour threshold to be almost reached or surpassed in a 50/50 forecast period as discussed above. Even if DSM fails to perform, a one-year commitment is short compared to five-year termination notice in other interruptible contracts such as in Florida.

XII. Renewable Portfolio Standards

In New England, five states have renewable portfolio standards in place. These standards require a specified share of electrical energy supply to be obtained via renewables. In some cases, there is fungibility with demand resources. Even so, there could be significant new stresses on the transmission grid resulting from very large increases in renewable supply at locations distant from load. One of the sensitivity cases is in part motivated by this potential.

XII.1 Cumulative Effect of RPS and Related Requirements and Goals

Exhibit F-41 shows ISO-NE's projected cumulative targets for renewable resources and energy efficiency in New England based on RPSs and related policies. The total is 30.4% of total ISO-NE's energy use by 2020, i.e., nearly one-third. By 2020, renewables alone are 19.4% of ISO-NE's energy use or approximately 28,000 MWh. Thus, the ISO-NE grid might face a very

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[91] Florida Public Service Commission Memorandum, Petition for determination of need for Glades Power Park Units 1 and 2 electrical power plants in Glades County, by Florida Power & Light Company, May 25, 2007.

[92] Direct testimony of Samuel Walters (Manager of Resource Planning for Progress Energy Florida), before the Florida Public Service Commission.

different future with large amounts of renewables and a need for a flexible capable transmission grid.

Exhibit F-41
Estimated New England RPS and Related Targets for Renewables and Energy Efficiency (GWh and %)

Line #	Use/Requirement Category	2010	2013	2017	2020
1	2010 ISO-NE electric energy use forecast	131,305	134,650	139,810	143,868
2	Existing—RPS targets for existing renewables[(a)]	8,980	9,132	9,167	9,157
3	New—RPS targets for new renewables[(b)]	5,231	8,584	13,662	17,136
4	Vermont goals[(c)]	160	695	1,516	1,662
5	Energy efficiency—targets for new energy efficiency and CHP[(d)]	3,316	6,617	11,369	15,770
6	Total RPS targets for renewable and energy efficiency	17,687	25,027	35,715	43,724
7	Total RPS targets for renewable and energy efficiency as a percentage of New England's projected electric energy use[(e)]	13.5%	18.6%	25.5%	30.4%

(a) This category includes CT Class II, new MA Class II, ME Class II, RI Existing, and NH Classes III and IV. This RPS category grows through time as a result of the growth in electricity demand. NH's classes also include some growth in the use of renewable resources to meet the RPS percentage of electric energy use.

(b) This category includes CT Class I, ME Class I, MA Class I, RI's "new" category, and NH Classes I and II.

(c) It has been assumed that Vermont's SPEED program will be renewed beyond 2012. Thus, this category includes VT's goal for renewable resources to meet 20% of the demand for electric energy by 2017 and assumed will meet 20% for 2020. Incremental increases up to 2017 were assumed for meeting this renewable goal.

(d) This incorporates only CT Class III (energy efficiency and CHP) and MA's goal of 25% energy efficiency by 2020 from its Green Communities Act.

(e) The numbers may not add to the totals shown because of rounding.

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 127

XII.2 Current Conditions and Potential Resources

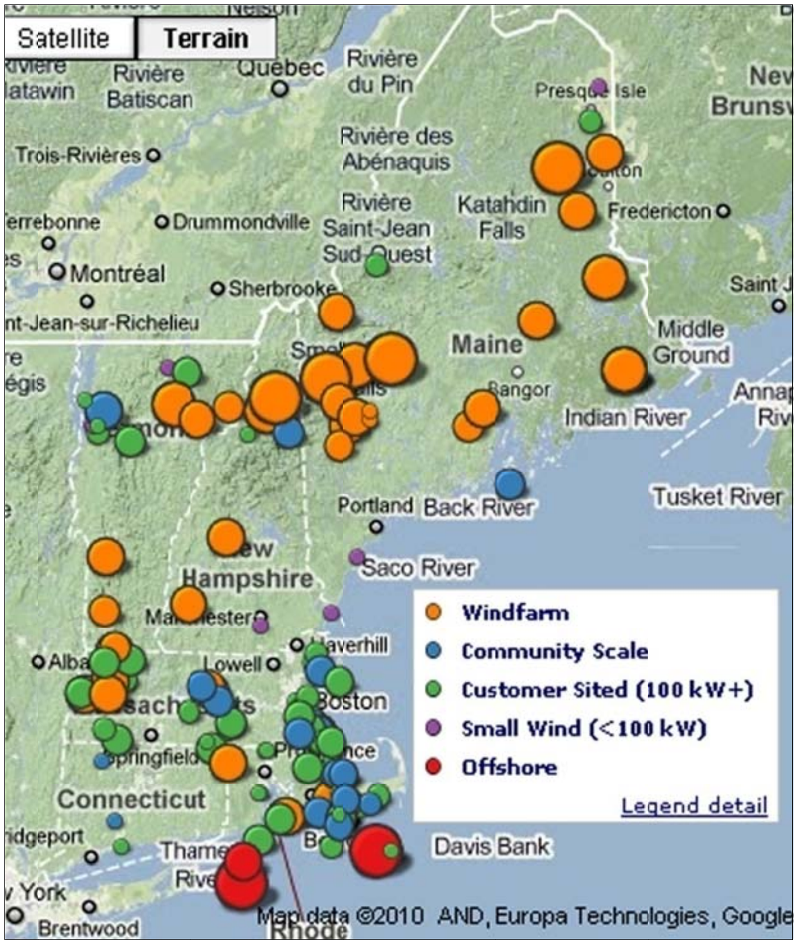
As of April 2010, only approximately 200 MW of utility-scale wind generation are on line in the ISO-NE New England system, of which approximately 170 MW are biddable assets. To illustrate how low April 2010 wind output is compared to the 28,000 MWh goal for 2020, if the 200 MW had an illustrative 30% capacity factor, the output would be less than 2 percent of the 2020 goal, i.e., 10,000 MW to 11,000 MW would be needed if all RPS requirements were met via wind. There are approximately 900 MW of other renewables on line, e.g., landfill gas, other biomass, municipal solid waste, wood and wood waste, solar, black liquor, and fire-derived fuels, but even so, this is well below the required amount. This is extremely small compared to projected need.

New England has approximately 3,100 MW of larger-scale wind projects in the queue, of which over 1,000 MW represent offshore projects and 2,100 MW represent onshore projects.[93] Exhibit

[93] *The 3,100 MW of wind includes wind projects in the queue, including affected non-FERC queue projects, as of April 1, 2010.*

F-42 shows a map of planned and active wind projects in New England. New England holds the potential for developing over 215 gigawatts (GW) of wind generation.[94]

Exhibit F-42
Planned and Active Wind Projects in New England, 2010

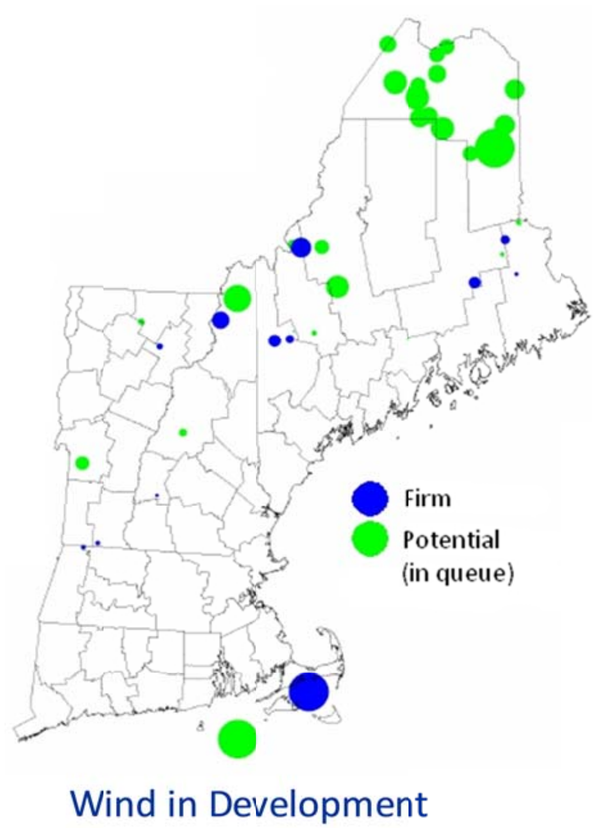


Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 145

Some of the best wind and biomass resources are in isolated locations (e.g., interior Maine) or on the coast. While there are significant amounts of potential capacity that are off-shore and close to load-centers (e.g., Cape Wind in SEMA and the proposed Block Island project in RI), the majority of on-shore wind is in geographically and electrically remote from the major load centers. Thus, renewable additions may require high transmission additions to strengthen the grid (see Exhibit F-43).

[94] *2009 Northeast Coordinated System Plan (May 24, 2010); http://iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/index.html.*

Exhibit F-43
Bulk Transmission System is Sparse in Wind-Rich Areas



Source: Various ISO-NE NEWIS presentations

XII.3 Related Renewable Resource and Energy-Efficiency Developments – Massachusetts

Another example of the stresses on transmission include the fact that a portion of the Massachusetts *Green Communities Act* is for the Secretary of Energy and Environmental Affairs to prepare a five-year plan for meeting the following renewable and energy-efficiency goals.

- Meet at least 25% of the state's electricity load by 2020 with demand resources that include energy efficiency, load management, demand response, and behind-the-meter generation.
- Have competitive LSEs meet at least 20% of their electricity load by 2020 through the use of new, renewable, and alternative energy generation. This goal encompasses the RPS target of 15%, plus the APS target of 5% by 2020.
- By 2020, reduce the amount of fossil fuels used in buildings by 10% from 2007 levels through increased efficiency.
- Plan to reduce total electric and nonelectric energy consumption in the state by at least 10% by 2017 through the development and implementation of a green communities program that encourages the use of renewable energy, demand reduction,

conservation, and energy efficiency, as well as the progressive adoption of Massachusetts's new *Stretch Energy Code*.[95] This building energy conservation code is intended to reduce at least 20% of the average overall annual combined energy consumption per square foot by all new and existing buildings in the municipalities that have adopted the code.

XII.4 Incremental RPS Targets for New Renewables Compared with Renewable Projects in the ISO-NE Queue

The ISO-NE recognizes the uncertainty of success for projects in the current queue. On the basis of assumptions used in the three scenarios presented, these projects would likely meet the incremental growth in the RPS classes for new renewables sometime between 2011 and 2015. For the 10-year planning horizon, the potential supply is greater than what is in the ISO-NE queue (as of April 1, 2010).[96] Most renewable projects have a short lead time of a few years, and many new projects are likely not yet in the queue. Also contributing to the greater supply is the development of small renewable projects "behind the meter" and the purchase of RECs from projects in neighboring balancing authority areas, which could help meet any shortfalls. Alternatively, affected LSEs can make Alternative Compliance Payments to the states' clean energy funds, which help finance new renewable projects.

Exhibit F-44 shows the renewable resource projects in the ISO-NE queue as of April 1, 2010. They total 3,515 MW, with wind projects comprising 87% of the total megawatts, and biomass projects, 11%. The remaining 2% of the projects comprises landfill gas, hydroelectric, and fuel cell projects. Exhibit F-45 shows the amount of energy available.

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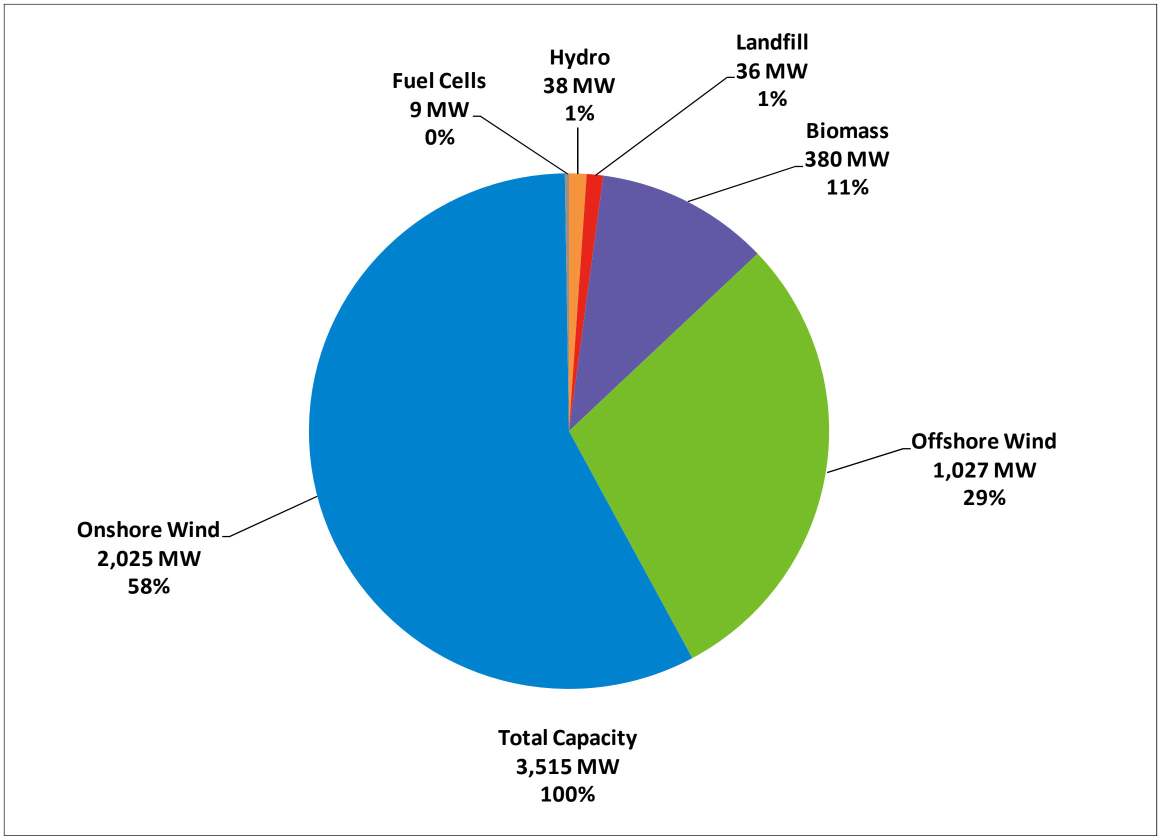
[95] Stretch Energy Code, 780 CMR Appendix 120 AA (Commonwealth of Massachusetts, 2009); http://www.mass.gov/Eeops/docs/dps/inf/appendix_120_aa_jul09_09_final.pdf.

[96] New England has the potential for developing over 215 GW of wind generation). New England also has cooperated regionally to promote the development of renewables and import them from the neighboring Canadian provinces.

Exhibit F-44
Proposed New England Renewable Resources in the ISO-NE Generator Interconnection Queue as of April 1, 2010 (MW and %)



NOTE: Totals include all queue wind projects in New England. The total amount of renewable resources is 3,515 MW.

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 130

Exhibit F-45
Estimated Energy from New England Renewable Energy Projects in the ISO-NE Queue as of April 1, 2010

Type (#) of Projects	Nameplate Capacity (MW)[(a)]	Assumed Capacity Factor (%)[(b)]	Estimated Annual Electricity Production (GWh)
Hydro (6)	38	25	83
Landfill gas (2)	36	90	284
Biomass (11)	380	90	2,996
Wind onshore (29)(c)	2,025	32	5,676
Wind offshore (3)	1,027	37	3,329
Fuel cells (1)	9	95	75
Total (52)	3,515	40(d)	12,443

(a) *Nameplate capacity* is a facility's megawatt capability designated and usually guaranteed by the manufacturer or developer.

(b) Capacity factors are based on the ISO's *2007 Scenario Analysis*. The wind capacity factors were adjusted to account for a generic assumption that wind turbines have a 90% availability. See http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf.

(c) This includes wind projects in New England (including affected non-FERC queue projects) and ignores duplicate listings for projects with more than one potential interconnection point.

(d) An equivalent capacity factor = [{total energy production (GWh) x 1,000}/{total capacity (MW) x 8,760 hours}].

Source: ISO New England 2010 Regional System Plan, October 28, 2010, page 131

XIII. CONCLUSION

The practicality of NTA for Interstate is affected by many of the issues discussed in this Appendix. With respect to supply side options, the appendix demonstrates that the most likely candidates are natural gas combined cycles. These plants will require contract for differences to be built and annual payments will be determined by ISO-NE market conditions. These conditions are uncertain and violate, and hence, payments will be potentially very large and volatile compared to those for Interstate. Causes of this dynamism include:

- Natural gas price volatility and effects on ISO-NE electrical energy prices
- Demand uncertainty as affected by economic trends and other favors
- Volatility in the capacity markets including in zonal sub-markets
- Changes in market rules, especially governing FCM
- RPS requirements which could increase dramatically
- Power plant retirements in response to an aging fleet and tighter environmental regulations.

Demand side resources are also subject to a degree to market uncertainty. Furthermore, ISO-NE already faces risks from heavy reliance on demand resources and the required demand side increases would add to this risk.