1. **What base case assumptions in the NEEWS Interstate Reliability Project ("IRP") Needs Analysis ("Needs Analysis") are driven by express NERC/NPCC requirements? Where there is a specific NERC or NPCC requirement please identify the requirement and explain why the requirement drives the specific assumption.**

There are numerous assumptions which are made in the development of a base case. This response covers those which have recently been noted as a concern by stakeholders.

NERC planning standards (TPL-001, -002, -003 and TPL-004) require that the pre-disturbance system (*i.e.,* the base case) "cover critical system conditions". NPCC's Directory 1 requires that stressed system conditions be evaluated. Because conditions can vary significantly from one system to another, the planning standards do not expressly define a stressed system. For example, each area has its own operating experiences and uniqueness based on past and current system design practices, its degree of reliance on imports as opposed to local resources, the degree of coincidence of peak occurrences between its various load pockets, and the relative contribution to peak of its industrial, commercial, and residential load components. Therefore, the standards require that the stressed conditions must be deemed appropriate by the Planning Authority (*i.e.,* ISO-NE). Answer 2 below explains why the stressed conditions for the IRP are appropriate.

NERC and NPCC expressly define the contingencies that are required to be modeled, for both N-1 and N-1-1 testing. Allowable system adjustments between the first and second contingency testing are also specified by NPCC. These are further described in the attached presentation "NESCOE Criteria Discussion" dated October 13, 2011 slides 10 through 19.

Where the NERC / NPCC requirements are left for interpretation by the ISO are described in the same presentation, slides 21 through 35.

Links to the following planning documents are found in the footnote:

- NERC TPL-001, TPL-002, TPL-003 and TPL-004 Transmission Planning System Standards[1]
- NPCC Directory 1 *"Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System"*, dated 12/15/09[2]

[1] http://www.nerc.com/page.php?cid=2|20
[2] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

- ISO New England Planning Procedure No. 3, *"Reliability Standards for the New England Area Bulk Power Supply System"*, dated 03/05/10[3]

**2. Where the needs analysis base case refl*ects areas where ISO-NE is using its judgment to determine what dispatche*s reflect a "reasonably stressed" system in accordance with the standard set forth in planning procedure 3 and planning procedure 5-3 (defining reasonably stressed conditions as those severe load and generation system conditions which have a reasonable probability of actually occurring'), what is the rationale for selecting the generator out assumptions in the dispatches? For example, in Dispatch B-2 both of the Millstone units are out, as well as Berkshire Power and Lake Road generating stations. In Dispatch B-1, Millstone 2 and 3 and Lake Road Generating Station are out of service. Please provide the rationale for these and the other dispatch configurations. While we understand ISO makes a deterministic assessment in contingency planning, we ask that a probabilistic evaluation be prepared as well.**

The needs assessment is based on the planning documents as outlined in Question 1, which includes PP-3. For a high-level discussion on generation assumptions, please see the presentation referred to in Question 1, slides 26 through 33.

More specifically, the B-1 and B-2 dispatches, for test years 2015 and 2020, respectively, were selected to stress the system in an east to west direction. The base dispatch for both of these included the following western unit assumptions:

Millstone 2 & 3 – out-of-service,
Berkshire Power – out-of-service,
Bear Swamp & Northfield – 50% power, and
Vermont Yankee – out-of-service.

Eighty percent (80%) of available quick-start units were modeled as in-service on in western New England. Millstone 2 and 3 were assumed to be the two large resources in western New England which are unavailable. This not only addresses a potential situation where these two units are unavailable, but also serves as a proxy for situations where there are numerous reductions on generator output as often occur under peak load conditions. Berkshire Power remained out-of-service to represent a typical amount of EFORD in western Massachusetts. Bear Swamp and Northfield Mountain were dispatched at 50% output because these resources often serve as reserve for New England and it

[3] http://www.iso-ne.com/rules_proceds/isone_plan/index.html

also covers situations where the ponds could not be totally replenished during non-peak hours. Vermont Yankee was assumed to be unavailable to address uncertainty with respect to the outcome of ongoing permitting and license renewal concerns with the plant.

The B5 (2015) and B6 (2020) dispatches were modeled to stress the system in a west to east direction. The eastern assumptions were as follows:

Seabrook – out-of-service,
Hydro Quebec Phase II – out-of-service, and
New Brunswick Import – set to zero.

Similar to the east to west analysis, eighty percent (80%) of available quick-start units were modeled on in eastern New England. Seabrook was assumed out of service to capture the first large resource being unavailable. Phase II was assumed out of service to capture the second large resource being unavailable. It should be noted that there is only a small contract to provide capacity over Phase II, which expires over the planning horizon. Therefore, there should be no credit given to this resource and arguments could be made that an additional resource should also be assumed unavailable in the East. However, due to the size of Seabrook and Phase II, assuming the unavailability of additional large resources did not seem reasonable. New Brunswick is assumed to be at zero, as their ability to provide support at peak load is questionable, especially in light of the continuing long-term outage of Pt Lepreau.

The B7 dispatch assumed the retirement of Salem Harbor and made up the change in generation in the east by importing 700+ MW over the New Brunswick tie. Therefore the B7 dispatch, from an east to west perspective, was very similar to the B6 dispatch. Since all of the Salem Harbor generators will be retired by June 1, 2014, this means that New England will now optimistically be counting on 700 MW from New Brunswick.

With respect to probabilistic evaluations, while they are used in various power system analyses, they are not used to any great extent for transmission planning. Probabilistic analysis which doesn't consider the full range of potential issues can be very misleading. For example, the probability of any specific circuit breaker failing to operate when required on the power system is low. However, when one considers the vast number of circuit breakers on the system and the complicated control systems required to initiate opening of a circuit breaker, it is quite likely that a circuit breaker will fail to operate somewhere on the system when it is needed. The question then becomes "Where will the failure occur?" Statistically speaking, the odds are that the breaker failure will be somewhere other than the specific breaker being evaluated. However, if this logic was applied to every circuit breaker individually, no circuit breaker would be assumed to fail. This is why much of the transmission planning criteria is written on a deterministic basis.

As far as dispatch and transfers are concerned, the system must be able to withstand a wide range of scenarios. While the specific dispatches assumed in a Needs Assessment may never occur, they need to provide a proxy for all of the other conditions which do occur. Something to consider is that Needs Assessments currently do not provide for the possibility of resource retirements – all resources are assumed to operate forever until they take appropriate actions through FCM. So while Millstone 2 and Millstone 3 may never be simultaneously unavailable again in the future, it also provides a reasonable proxy for Millstone 3 being out of service, Millstone 2 operating, and retirement of units such as Middletown 4 and Montville 6.

In addition to potential retirements, New England has also experienced a number of unlikely scenarios which have rendered significant amounts of generation unavailable for an extended period of time, which can be attributed to the age or unexpected events of the generation fleet. Some examples include:

- Simultaneous outage of Millstone 1, 2, 3, and Connecticut Yankee which covered years
- Retirement of New Boston 1 followed by a fire on New Boston 2 which destroyed the unit
- Explosion at Salem Harbor which shut down all four units
- Extended outage of all four Northfield Mountain generators

After outages such as those listed above occur, the resultant system now becomes the new base system which must be operated such that it can withstand new contingency events.

General Electric's Multi-Area Reliability Simulation (MARS) program is one resource planning tool among many that relies on probabilities to determine a Loss-Of-Load Expectation index.

> "The MARS modeling software enables the electric utility planner to quickly and accurately assess the ability of a power system, comprised of a number of interconnected areas, to adequately satisfy the customer load requirements. Based on a full sequential Monte Carlo simulation, MARS performs a chronological hourly simulation of the system, comparing the hourly load demand in each area to the total available generation in the area, which has been adjusted to account for planned maintenance and randomly occurring forced outages."[4]

[4] http://site.ge-energy.com/prod_serv/products/utility_software/en/ge_mars.htm

While this approach shows the likelihood[5] of not being able to meet load with available generation, it is strictly a resource adequacy planning tool and does not model the transmission network. Inputs are typically 8760 hours per year of load magnitudes, maintenance periods for generators, and recent forced outage rates of generators. No specific characteristics of the units – ramp rates, start-up times, shut-down times, output limitations based on temperature, etc. – are modeled. Because transfer limits into load pockets and out of export areas are modeled, it can also signal the need for a transmission upgrade to increase an import or export constrained area.

3. **Has ISO-NE considered modeling the base case generator availability using an historical outage pattern rather than selecting certain units to be taken out of service? If ISO-NE believes that this different approach (combined with a 90/10 extreme weather forecast) would not meet the reasonably stressed criteria, please provide the rationale for this belief.**

ISO-NE has considered historical generator availability where it is appropriate. This practice is reflected in the outage rate assumed for fast start resources. The reasoning for using dispatches other than those based on historical outage patterns was provided in the response to Question 2.

4. **Given that Planning Procedure 3 sets forth a "reasonably stressed" standard and the use of a 90/10 extreme weather forecast load level, why would the emergency status of certain generators disqualify these generators from inclusion in generation considered available (to the extent of their FCM qualification level)?**

Real-Time Emergency Generation (RTEGs) is not considered during reliability analyses for the following reasons:

First, they are typically emissions limited by environmental regulations and can only run a certain number of hours per year. Therefore, they may not be available during the third day of a heat wave if they have operated up to their emissions limits.

[5] The criteria is satisfied if load is not able to be met with available generation only once in a ten-year period.

Second, RTEGs are called during Action 6 of ISO Operating Procedure 4[6], which is considered an emergency action. Modeling these generators as in service in a reliability analysis would then have the effect of planning the system to be operated under emergency conditions, which is not acceptable.

To put this in perspective, the total RTEGs for both eastern and western New England are approximately 350 MW each. For the western area, which grows at roughly 120 MW per year in the latter years of the forecast, this would equate to a 2 to 3 year delay of need, assuming all the units were available when called upon. For the eastern growth of 200 MW per year, it would be a 1 to 2 year delay of need. Similarly, for Connecticut which grows at 80 MW per year and has roughly 250 MW of RTEGs, it would be about a 3 year delay of need.

5. **What is the rationale for not considering one generator or generating station out of service combined with modeling load levels at a 90/10 extreme weather peak?**

We are examining the needs on a system wide basis for the NEEWS study. It is not uncommon to have at least two units out in all of western or eastern New England on a peak day.

From slide 28 of the attached, over the past ten years during the peak day of June, July, and August, there has been approximately 2,500 MW or greater of generation out of service 5 times and had reached a high of 3,160 MW. Furthermore, during the top ten peak load days of June, July, and August over the past ten years, New England's generator outages reached a high of 4,270 MW. On July 22, 2011 forced outages and reductions totaled 3,403 MW coincident with the 90/10 seasonal load level. See slide 34 of the attached.

It should also be noted that reductions and unit outages are not decoupled from summer heat consistent with a 90/10 peak day. Instead, it is the heat that drives many of the unit outages and reductions. It is under these conditions that reductions caused by such things as cooling water discharge temperature limitations, low water for hydro generators, generator outages due to equipment failures, etc. become more prevalent.

Also, see response to question 2 above.

[6] http://www.iso-ne.com/rules_proceds/operating/isone/index.html

**6. To what extent would substituting one generating unit or station out for the multiple generator stations out in the dispatches reduce the need?**

To answer questions of this nature, Figures 5-22, 5-23, and 5-24 were included in the needs assessment report[7], with associated resource requirement tables, 5-31, 5-32 and 5-33, respectively. These are all aimed at determining, "does the system under study have enough resources plus import capability to meet its native peak load under contingency conditions?"

For example, referencing Figure 5-23 on page 69, the need for the project occurs in 2018, where the black line meets the intersection of the green and orange colored areas. The horizontal portion of the black line is at a value of 10,235 MW, as can be found in Row M of Table 5-32, Total Available Resources.

To figure out the impact of adding a 265 MW additional resource in western New England, either the figure or the table could be used. Using the figure, the resource total would move up to the 10,500 MW line (10,235 + 265), and that line would now cross the intersection of the green and orange colored areas in 2020. Thus, the year of need would shift out 2 years due to the addition of 265 MW of resources. Similarly, Rows R, S and T could be examined in Table 5-32 which show a resource requirement of 10,506 in 2020 and a shortage in the same year of 272 MW, which would be eliminated for the most part with a new 265 MW resource.

This same technique can be repeated for the eastern New England area and for the Connecticut Import area to determine the impact of adding or subtracting resources.

**7. To what extent would assuming that the average level of energy efficiency in New England's first four forward capacity auctions continues to 2020 reduce or delay the need for NEEWS ITC?**

(In responding to this question, the ISO assumes that "ITC" refers to the Interstate Reliability Project.)

[7] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/nov302010/index.html

A response to this question has been previously provided. The ISO response to NESCOE question 2 from late 2010 is found in the Final Version-Response to NESCOE's Comments on the IRP Needs Re-assessment document[8].

**8. What assumptions regarding Tie Optimization (or CTS) were considered in flow assessments?**

The two design options for future real-time interface scheduling, Tie Optimization (TO) or Coordinated Transaction Scheduling (CTS), were not considered in this analysis. These proposed market-based solutions both deal with the real-time scheduling of energy transactions over Area interfaces, and not with capacity obligations and long-term transmission planning.

For this analysis, the assumptions regarding imports and exports from external Areas are described in Section 3.1.9 of the updated needs assessment.

**9. What assumptions for benefits from advanced technology (such as Smart Grid) were included in the analysis?**

This question is extremely broad. In determining the system needs, similar to the answer to question 8, it is difficult to predict what the impact of some of these newer concepts may have. On the transmission system itself, advanced technologies, such as FACTS devices, over and above what have already been employed on the system are considered as appropriate in the Solutions Assessment. The impact of smart metering and other similar technologies which are sometimes rolled into "Smart Grid" is unknown at this time. Needs Assessments can easily accommodate such load reductions through participation in the Forward Capacity Market.

In accordance with the ISO's Tariff, resources that clear in the Forward Capacity Market or are backed by a State RFP are modeled in needs assessments. These criteria provide a level of certainty that the resources will be placed-in service and is necessary given that roughly 80% of resources in the queue are never built.

[8] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/nov302010/response-nescoe-final.pdf

**10. What allowance was made for likely Order 745 impacts?**

In accordance with Attachment K of the Tariff[9], the regional planning process accounts for those resources that clear in the Forward Capacity Market or are backed by a State RFP in needs assessments.

[9] http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/oatt.pdf, pages 290-318