

Identification of Designated Congestion Areas and Calculation of Constrained Hours Under Market Rule 1, Appendix A

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Summary

This report, required by Appendix A to Market Rule 1, explains the ISO's Designated Congestion Area (DCA) methodology, proposes DCAs, and seeks stakeholder input on methods and procedures for designation and calculation of constrained hours. The ISO used operations procedures, system planning reports, and congestion data from the current market to identify candidate DCAs. The DCA candidates are Northeastern Massachusetts/Boston (NEMASS/Boston), Connecticut (CT)¹, Southwest Connecticut (SWCT), and Norwalk/Stamford (Nor/Stam). These areas are repeatedly identified as likely DCA candidates by the various sources. Each was evaluated using four methodologies for the calculation of constrained hours in a DCAs. These methods rely on a combination of current system dispatch procedures, out-of-merit dispatch data, system operating criteria, and bid data to calculate congested hours in a sub-area. Due to data limitations and the emerging nature of the problem, Northwest Vermont was not subject to detailed evaluation at this time, though it has begun to appear as an area with increasing congestion.

The evaluation approaches to calculating an annual number of constrained hours, in order of refinement, are:

Approach 1. Number of hours in each sub-area in which there was at least one unit "flagged"² and dispatched for congestion by ISO operations.

Approach 2. Number of "on-peak" hours in each sub-area in which at least one unit was flagged and dispatched for congestion by ISO operations.

Approach 3. Number of hours in each sub-area during which:

- a. Loads minus in-merit sub-area generation exceeded transmission interface limits and,
- b. Out-of-merit generation resident in that sub-area was flagged and dispatched.

Approach 4. Number of hours in each sub-area during which:

- a. Loads minus in-merit sub-area generation exceeded transmission interface limits and,
- b. Out-of-merit generation was dispatched to serve that sub-area.

¹ CT is the area of Connecticut that is exclusive of SWCT and Nor/Stam. The DCA threshold in CT would not be applicable to SWCT or Nor/Stam.

² "Flagged" means identified as running out-of-merit to support the transmission system.

Each of these methods was used to calculate a number of congested hours for fiscal year 2001 (FY 2001)³ to allow a comparison of the techniques for consistency and also to provide checks on each of the calculations. The results of the four methods were consistent given the different assumptions, thereby providing confidence in the calculation methods and results. Each of the four methods indicates that sufficient congested hours exist that NEMASS/Boston, CT, and SWCT should be identified as DCAs. Excepting the least sophisticated methodology (Approach 1), three of the four approaches suggest that Nor/Stam is not sufficiently congested to merit separate DCA status at this time, with only small numbers of congested hours.⁴ As a part of SWCT, the ISO proposes that Nor/Stam would be part of the SWCT DCA. The ISO seeks comment on this recommendation not to select Nor/Stam as a distinct DCA. These identifications are consistent with the multiple sources reviewed by the ISO in identifying potential DCAs.⁵

Market Rule 1, Appendix A provides upper and lower bounds of 2000 and 500 hours on the number of congested hours to be used in the DCA Threshold calculation. The table below shows the calculated number of hours that would be used to calculate the DCA Threshold for each method for fiscal year 2001. When the results of each method are combined with the bounds provided by the rule, the number of congested hours changes significantly across methods only for SWCT.

Congested Hours in Threshold Calculation by Method and DCA for FY 2001

Method	NEMASS/Boston	CT	SWCT
Approach 1	2000	2000	2000
Approach 2	2000	1829	1527
Approach 3	2000	2000	1226
Approach 4	2000	2000	1505

This consistency shows that the choice of method is not the determining factor in identifying the selected DCAs, and that the number of congested hours stays in a relatively narrow range. The ISO recommends Approach 4 as the most appropriate methodology, as it utilizes the most complete available data. Applying Approach 4 over the last three fiscal years, in conjunction with the upper bound on hours results in consistent numbers of congested hours each year.

The impact of the difference between 2000 and 1500 constrained hours, in the threshold calculation, is expected to be on the order of \$15/MWh based on previous ISO estimates. The ISO also evaluated a number of forward-looking sources to determine if the

³ FY 2001 runs from May 2001-April 2002.

⁴ The number of congested hours is below 350 for three of the four approaches, with Approach 1, the least refined method, showing congested hours above 600. Approach 4, the preferred approach, shows congested hours of less than 100.

⁵ While Nor/Stam is generally identified as a reliability problem because of the need for improved second contingency coverage, the analysis presented here shows that economic congestion occurs only a small number of hours per year. Thus while the sub-area is especially sensitive to line or plant outages, it is not generally congested.

identified DCAs were still likely to be significantly congested in 2003, or if areas not identified may warrant DCA treatment. While forward-looking data are inherently uncertain, and thus warrant less weighting in the decision, the forward-looking sources and analysis suggested that the identified DCAs will continue to experience significant congestion in 2003. These sources include RTEP02, the recent System Planning Study of CT and recent ISO analysis of projected congestion in NEMA/Boston using anticipated transmission improvements and expected new capacity.

I. Introduction

Market Rule 1, Appendix A requires that the ISO identify Designated Congestion Areas (DCAs), if any, calculate the number of constrained hours into each of the identified areas, provide written notice to the NEPOOL Markets Committee of its determinations, and seek comment on these methods and procedures. This information is to be used to set thresholds for mitigation as described in the rule. This report explains the ISO's DCA methodology, calculates constrained hours, proposes DCAs, and seeks stakeholder input on the methods and procedures for designation and calculation of constrained hours.

The ISO has examined several approaches to determining the sub-areas within New England that face chronic transmission congestion both historic and forward-looking.⁶ The determination of these areas is an important element of market monitoring and mitigation under Market Rule 1. These different approaches utilize different data sets available to the ISO and different logic to sort the data and calculate the number of constrained hours. Each method is presented here to show the evolution of the analysis and to show that the preferred method produces results consistent with alternate methodologies, given the changing logic across approaches. Recognizing that sub-area congestion varies over time, Market Rule 1 allows for the periodic revision of the sub-areas considered to be DCAs. This is the first attempt to define DCAs.

The ISO developed four approaches to determining DCAs based on the annual number of constrained hours occurring within each sub-area. Sub-areas are as defined by ISO system operations and reported in congestion reporting documents.⁷ These approaches are:

- Approach 1. Number of hours in each sub-area in which there was at least one unit “flagged”⁸ and dispatched for congestion by ISO operations.
- Approach 2. Number of “on-peak” hours in each sub-area in which at least one unit was flagged and dispatched for congestion by ISO operations.
- Approach 3. Number of hours in each sub-area during which:
 - a. Loads minus in-merit sub-area generation exceeded transmission interface limits and,
 - b. Out-of-merit generation resident in that sub-area was flagged and dispatched.

⁶ For the purposes of this document, congestion is defined as occurring when the desired economic imports into a sub-area exceed the capacity of the sub-area's interface, requiring more expensive local generation to be dispatched.

⁷ The sub-area definitions used by system operations are nearly the same as those used in RTEP02.

⁸ “Flagged” means identified as running out-of-merit to support the transmission system.

Approach 4. Number of hours in each sub-area during which:

- a. Loads minus in-merit sub-area generation exceeded transmission interface limits and,
- b. Out-of-merit generation was dispatched to serve that sub-area.

The number of annual congested hours from each approach was calculated for Fiscal Year 2001. These results show the expected internal consistency among approaches. The next section discusses the calculation methodology in greater detail. Section III describes how potential sub-areas were chosen. Section IV describes the data used in calculations. Section V provides results. Section VI discusses future congestion expectations. Section VII states the ISO's conclusions.

II. Discussion of the DCA Analysis Approaches

Approach 1 produces a calculation of constrained-hours based on out-of-merit congestion dispatch and flagging by ISO operations. These data are the basis for the congestion summary in the ISO's 2001-2002 Annual Markets Report, pages 25-26. For each sub-area, Approach 1 calculates the annual number of hours in which at least one unit produced out-of-merit energy to serve that sub-area. The designation is based on ISO operations flagging and assignment data. This approach establishes an upper bound on the number of constrained hours in a sub-area since it includes all hours with out-of-merit MWs flagged for congestion. No other tests are applied to determine the presence of congestion within that hour. This number is an upper-bound, as a unit run to relieve congestion is flagged for the duration of its minimum run time, not just the hours required to relieve congestion. Thus, this approach includes hours when a flagged unit is running to fulfill minimum run time requirements, for example, but may not be needed to relieve a constraint.

Approach 2 examines only a subset of the results from Approach 1; namely, the weekday hours ending 8 a.m. through 10 p.m. The rationale for considering only these on-peak hours for Approach 2 is to reflect the fact that the units flagged for congestion often run during an off-peak hour to satisfy the operating characteristics of those units, rather being required to meet sub-area load during that hour. Approach 2 attempts to correct for this problem by limiting the analysis to only those hours most likely to experience congestion. The hour range was determined with input from system operations.

In the absence of information on sub-area loads and transmission interface limits for each hour, Approaches 1 and 2 calculate congested hours based solely on identified out-of-merit generation dispatched to relieve congestion into a sub-area. While Approaches 1 and 2 are useful calculations, they reflect the inefficiencies of the manual congestion dispatch process and the presence of unit operating constraints. Approaches 3 and 4 refine these estimates by identifying the conditions which cause congestion into a sub-area in each hour, in addition to the out-of-merit generation corresponding to each sub-area for that hour.

Approach 3 derives a constrained hours figure based on: (a) the actual loads in each sub-area (b) transmission interface limits developed by the ISO's Power System Operations group; (c) in-merit generation in each sub-area, and (d) the flagged out-of-merit generation dispatched from units located within each sub-area. Approach 3 defines an hour as constrained if the sub-area load minus sub-area in-merit generation exceeds the sub-area transmission interface limit, and flagged out-of-merit generation is produced in the sub-area during that hour.

Approach 4 is an improvement on Approach 3 that recognizes the nested nature of some sub-areas. Approach 4 calculates a sub-area's out-of-merit generation in terms of the generation dispatched to relieve the sub-area's constraint, rather than the out-of-merit generation produced only by units "resident" within that sub-area.

The number of constrained hours calculated using Approaches 2, 3 and 4 should be less than the number calculated using Approach 1. Approach 2 uses the same logic as Approach 1, but examines fewer hours. Approaches 3 and 4 reflect only the out-of-merit generation serving the sub-area when sub-area loads exceed the transmission interface limit. Note that no approach counts an hour as congested into a sub-area if no flagged out-of-merit generation is dispatched for the sub-area. This is a small number of hours.

Approach 4, by combining hours when interface limits are binding with operations' dispatch decisions, avoids the expected over counting of Approaches 1 and 2. Because it uses sub-areas as assigned for operational purposes rather than simply relying on physical location, it is more accurate than Approach 3. These operations assignments reflect a units electrical location, which may differ from its physical location, especially with nested areas. Since Approach 4 most accurately reflects congestion that was relieved by out-of-merit dispatch, it is the approach recommended by the ISO- for identifying DCAs and calculating the amount of congested hours.

III. How Sub-areas were Selected for Evaluation

Three distinct sources were used to identify sub-areas as potential DCAs. First, Approach 1 was applied to each of the 24 sub-areas used as targets in the ISO operations flagging process. Based on those results, the sub-areas with the largest number of hours in which there was flagging for congestion were identified. Second, only the sub-areas included consistently in the daily Generation Requirements for Transmission Constraints (GRT) spreadsheets were kept as candidates for evaluation. Of necessity, the GRT spreadsheets identify chronically congested sub-areas and contain the interface limits needed for Approaches 3 and 4. Finally, RTEP02 was used as a check on the selected sub-areas, as well as providing a forward look at expected congestion. The four candidate sub-areas: Connecticut, Southwest Connecticut, Norwalk-Stamford, and Northeast Massachusetts/Boston, consistently appeared as important sub-areas in each source. Each, also has received attention in the ISO's Annual Markets Reports and in other documents detailing congestion costs in New England. These include RTEP02⁹ and the recent assessment of Connecticut reliability needs.

⁹ Regional Transmission Expansion Plan 2002 (http://www.iso-ne.com/transmission/Regional_Transmission_Expansion_Plan/RTEP_2002)

Calculations consistently show that each of these sub-areas also contains limited competition. The 2000-2001 Annual Markets Report notes that each sub-area has an HHI significantly above that of New England as a whole and above the 1,800 “rule-of-thumb” HHI cited as being used by the U.S. Department of Justice. This is also consistent with calculations in the congestion report prepared by Christensen Associates designed to evaluate transmission congestion in New England prior to SMD implementation.¹⁰ In addition, the ISO calculated the hourly Residual Supply Index by proposed DCA for FY2001, inclusive of net imports. These results, shown below, also show limited competition in each proposed DCA.¹¹

**Table 1
Herfindahl-Hirschman Index By Designated Congestion Area**

DCA	Fiscal Year 2000	December 2002
Northeastern Massachusetts/Boston	4,900	4,840
Southwest Connecticut	2,800	2,342
Connecticut	2,600	2,481

**Table 2
Residual Supply Index By Designated Congestion Area:
May 2001 – April 2002**

DCA	RSI excluding largest pivotal bidder		RSI excluding 2 largest pivotal bidders	
	Hours when RSI < 110	Hours when RSI < 100	Hours when RSI < 110	Hours when RSI < 100
Northeastern Massachusetts/Boston	704	359	3,553	1,997
Southwest Connecticut	8,552	8,289	8,687	8,687
Connecticut	7,849	6,956	8,687	8,687

One sub-area identified by RTEP02 as a potential reliability problem, Northwest Vermont, was not included in this analysis. Northwest Vermont has been identified as a chronic problem area only recently. This is evidenced by the fact that the daily GRT spreadsheet has only recently been updated to systematically include Northwest Vermont data. This recent addition means that insufficient data exists to apply Approaches 3 and 4, which are the preferred methods for calculating constrained hours. While the ISO is not

¹⁰ http://www.iso-ne.com/special_studies/Congestion_Management_Under_SMD/Appendix_E_-_Christensen_Study/

¹¹ Note that RSI calculations under 100 indicate that at least one supplier is pivotal, or needed to serve load, while calculations under 110 suggest that the market may not be competitive.

able to evaluate DCA status for Northwest Vermont at this time, it will continue to assess available data for DCA designation in the future.

IV. Data

Approaches 1 and 2 require calculating only the number of hours for which out-of-merit generation was dispatched to relieve congestion in a given sub-area. The information required is the asset identifier, sub-area identifier, and congestion MW produced for each hour. The source of this data is the ISO's Market Monitoring and Mitigation Department's Secure Master Table files. These files are populated with data from the Transmission Related Abnormal Generation Operation (TRAGO) reports issued daily by the ISO's forecasting group. These reports contain the units, the sub-area, and the required output for each flagged unit.

Approaches 3 and 4, in addition to the data required for Approaches 1 and 2, require hourly data on sub-area loads, sub-area in-merit generation, and sub-area transmission limits. Calculations of in-merit generation are based on re-declared bid data and hourly clearing price data from the ISO's Market Systems database. Generation is in-merit if it is bid below the hourly ECP. The source of the hourly sub-area load and transmission limit information is the ISO's Power System Operations' daily GRT spreadsheets. A sub-area's load is calculated by multiplying NEPOOL reported load by the sub-area's share of NEPOOL reported load based on the GRT spreadsheets. These sheets were developed from prior studies of New England load distribution (e.g., CELT reports) and are used by ISO System Operations to determine the need for out of merit generation. The transmission limits used are the forecasted first contingency (n-1) limits for each sub-area; use of the first contingency limit is consistent with the calculations specified in Appendix A of Market Rule 1.

Both Approaches 3 and 4 use the Secure Master Table files in order to map the asset generating out-of-merit to the appropriate sub-area. However, Approach 3 maps the asset to the sub-area in which it is located by using the Unit Default Location database in the Secure Master Table Files, while Approach 4 maps the asset to the sub-area that it is serving as determined by the sub-area identifier contained in the Unit_Data_T1 database in the Secure Master Table Files, populated from the daily TRAGO sheets.

V. Results

Table 3 summarizes the number of constrained hours by sub-area for FY2001 using the four approaches detailed above. The sub-areas considered are: Connecticut (CT), Southwest Connecticut (SWCT), Norwalk/Stamford (Nor/Stam) and Northeastern Massachusetts/Boston (NEMASS/Boston).¹²

¹² Although RTEP02 has identified Northwest Vermont as a potential load pocket, the data necessary for Approaches 3 and 4 has only been developed by ISO operations since September 2002 because NW Vermont has only recently become a more chronic problem. At the present time, the limited data indicates that NW Vermont has not been a consistent problem in the past. However, the ISO will continue to evaluate NW Vermont and any other potential emerging constrained areas for designation as DCAs.

Table 3
Number Of Constrained Hours By Sub-Area-FY 2001

Year	CT	SWCT	NOR/STAM	NEMASS/BOSTON
Approach 1	4,070	2,843	656	8,730
Approach 2	1,829	1,527	336	3,891
Approach 3	3,642	1,226	163	3,600
Approach 4	3,433	1,505	92	3,601

Approach 1 shows the hours for each sub-area during which energy from at least one flagged unit is generated to relieve congestion in the sub-area, without regard to whether congestion would have occurred without that generation. For example, Approach 1 calculates 8,730 constrained hours for FY2001 in NEMASS/BOSTON, even though Table 4 shows that NEMASS/Boston's load exceeded its transmission interface limits only during approximately 3,626 hour that year. This difference is attributable to the inflexibility of NEMASS/Boston units dispatched for congestion relief and to the need for second contingency coverage in the NEMASS/Boston area.

Approach 2 is simply a subset of Approach 1, accounting only for weekday on-peak hours between hour-ending 8 am and 10 pm, when congestion is expected to occur. Approach 2 seeks to remove hours during which units flagged for congestion are likely to have run in order to satisfy the operating characteristics of those units, rather than to meet sub-area load. To the extent that congestion occurs during off-peak periods, Approach 2 will understate the number of constrained hours. Conversely, Approach 2 will continue to overstate the number of constrained hours for areas with inflexible units and relatively short periods of congestion. By design, the congested hours calculated by Approach 2 are strictly less than calculated under Approach 1.

Approach 3 calculates constrained hours by combining flagging data used in Approaches 1 and 2 with hours in which net sub-area loads exceed each sub-area's transmission interface limits. For SWCT, Nor/Stam, and NEMASS/Boston, the calculated hours using Approach 3 were lower than under Approach 2, suggesting that even on-peak hours with flagged generation overstate the number of congested hours. CT is much higher, suggesting that significant off-peak congestion occurs over the CT interface. Approach 3, surprisingly is also higher than Approach 1. This is because generation resident in CT is often dispatched to support other areas (e.g. voltage in Middletown). Approach 4 corrects for this mis-assignment.

Approach 4 calculates constrained hours in a manner similar to Approach 3, except that it calculates the number of hours during which the sub-area was served by any unit flagged and assigned to that sub-area, not just units resident in the sub-area. Note that because of the nested nature of the sub-areas in CT, a unit may relieve constraints in more than one sub-area. This calculation accepts the sub-area associated with the unit for that hour by system operations. The hour may not count as a constrained hour in the other sub-area if no out-of-merit generation is assigned to the sub-area. Approach 4, when compared with Approach 3, shows that generation in one sub-area is often dispatched to relieve a constraint in another sub-area.

Tables 2 and 3 show the number of hours per year in which loads exceeded the sub-areas' transmission interface limits, and the number of constrained hours calculated using Approach 4 from the beginning of the markets through April 2002 (FY1999 through FY 2001). Table 4 shows that loads in each sub-area exceed the transmission limits into each sub-area a large number of hours. This number is substantially greater than the number calculated under Approach 4 because in-merit generation is not considered.

Table 5, which shows the calculated number of congested hours using Approach 4 for the past three fiscal years, shows significant year-to-year variation in congested hours. This is not surprising as many factors, including weather, transmission outages and unit availability influence transmission congestion.

Table 4
Hours Per Year In Which Loads Exceeded The Transmission Interface Limits
Ignoring In-Merit Generation-FY1999-FY2001

Year	CT	SWCT	NOR/STAM	NEMASS/BOSTON
FY2001	8,760	3,736	219	3,626
FY2000	7,895	4,535	258	4,180
FY1999	8,021	5,346	917	4,506

Table 5
Approach 4 Calculation Of Constrained Hours By Sub-Area-FY1999-FY2001

Year	CT	SWCT	NOR/STAM	NEMASS/BOSTON
FY 2001	3,433	1,505	92	3,601
FY 2000	3,022	2,730	25	4,148
FY 1999	2,557	1,309	83	3,727

Note: FY 1999 and FY 2000 calculations are missing data for 5 days and 2 days .
Source: ISO-NE Power System Operations.

Table 5 shows that CT, SWCT and NEMASS/Boston each experience large numbers of congested hours each year, and thus warrant selection as DCAs. Nor/Stam experiences very few congested hours using this calculation methodology and thus does not merit separate DCA selection. Rather, Nor/Stam will be included as part of the SWCT DCA as the ISO Seeks comment on this decision.

Approaches 3 and 4 Compared

Approaches 3 and 4, while similar, lead to somewhat different results. Further discussion can better illustrate the reasons for these differences. The differences in the constrained-hour calculations using Approaches 3 and 4 are explained by the fact that CT, SWCT, and Nor/Stam constitute a series of “nested” load pockets, in which units in the smallest load pocket (Nor/Stam) can serve the larger load pockets, while units in the largest load pocket (CT) can serve sub-areas inside and outside the “nest.” Therefore, the procedures followed by the ISO’s Power System Operations to assign out-of-merit generation within

the “nest” explain in large part why the differential between the results of Approaches 3 and 4 varies across sub-areas and over time. Table 6 shows how sub-area assignments by operations can differ from a unit’s physical location.

Approach 3 classifies “Connecticut-resident” generation as CT, while Approach 4 classifies this generation as either SWCT or CT, based on the sub-area served. Since CT loads almost always exceed the transmission interface limits during the period analyzed, the larger number of hours of out-of-merit MW based on “Connecticut-resident” generation under Approach 3 necessarily results in a larger number of constrained hours than using Approach 4. Under Approach 3 whether Connecticut-resident generation is assigned to SWCT or CT is not considered.

Units located within the Nor/Stam sub-area provide another useful example. Throughout FY2001, out-of-merit generation from “Norwalk/Stamford-resident” units seldom served Nor/Stam when its sub-area load exceeded transmission limits. During many of these congested hours, Nor/Stam was served instead by in-merit generation. Therefore, Approach 3 produced more constrained hours for Nor/Stam than did Approach 4.

Table 6
Connecticut Constrained Hours FY 2001 By Location Of Units Serving Connecticut

Connecticut	Total constrained hours	Hours CT units serving CT	Hours Nor/Stam units serving CT	Hours SWCT units serving CT	Sum of hours of units serving CT
May-01	574	319	293	241	853
June-01	482	432	58	121	611
July-01	165	131	0	38	169
August-01	262	219	0	59	278
September-01	66	49	0	17	66
October-01	111	111	0	21	132
November-01	160	107	66	81	254
December-01	96	95	0	7	102
January-02	216	194	0	39	233
February-02	352	337	27	58	422
March-02	633	578	60	152	790
April-02	316	307	0	34	341
TOTAL	3,433	2,879	504	868	4,251

Note: Sum of units exceeds the total constrained hours since multiple units/areas serve Connecticut DCA during the same constrained hours.

These results for the nested sub-areas in Connecticut may be contrasted with those for NEMASS/Boston. For NEMASS/Boston, Approaches 3 and 4 produce nearly identical results because, with rare exceptions, the only units that can be dispatched out-of-merit to relieve NEMASS/Boston congestion are “NEMASS/Boston-resident.” Thus, NEMASS/Boston results are nearly identical using either approach.

VI. Comparison with Forward-Looking Studies

The ISO evaluated a number of sources to determine if the identified DCAs were still likely to be significantly congested in 2003, or if areas not identified may warrant DCA treatment. While forward-looking analysis is inherently uncertain, and thus warrants less weighting in the decision, the forward-looking sources and analysis suggested that the identified DCAs would continue to experience significant congestion in 2003. These sources include RTEP02, the recent System Planning Study of CT and recent ISO analysis of projected congestion in NEMA/Boston using anticipated transmission improvements and expected new capacity.

The results of this analysis are consistent with load pockets identified in other ISO reports. Specifically, RTEP02 identifies SWCT, Nor/Stam, NEMASS/Boston and Northwest Vermont as future reliability problem areas.¹³ The Technical Assessment of the Generating Resources Required to Reliably Operate Connecticut's Bulk Electric System 2003 & 2006 finds that CT as a whole, and SWCT and Nor/Stam as nested sub-areas, face important reliability concerns. Importantly, RTEP02 identifies only NEMA/Boston as expecting significant improvement before or during 2003. The ISO undertook economic modeling of NEMA/Boston, incorporating the identified structural improvements, to determine if significant congestion was projected to exist in 2003.

To model NEMA/Boston in 2003, the ISO replicated its Approach 4 analysis with two changes: increasing load from 2002 by the forecast increase, and including projected interface limits and new capacity additions from RTEP02. The new capacity was modeled with a 30% constant derating to reflect the ISO's experience with new unit availability in New England. The result was over 700 hours of congestion projected for NEMA/Boston for 2003.

This suggested that NEMA/Boston will still experience a significant number of congested hours in 2003. The ISO does not propose to reduce the number of congested hours used in the threshold calculation for NEMA/Boston based on this projection, but rather interprets the projection as confirming the appropriateness of designating NEMA/Boston as a DCA

Because NEMA/Boston has the prospect of significantly reduced congested hours due to recent transmission upgrades and expected new unit entry, it deserves special attention in the designation process. This prospect does not necessarily imply that NEMA/Boston should not be a DCA for the following reasons:

- The historical evidence clearly shows that NEMA/Boston has been highly congested.
- Reduction of congestion is highly dependent upon two new, large baseload generators projected to enter commercial operation in the first quarter of 2003. The ISO's experience with new unit commercial dates is that generally the target commercial dates are optimistic, with 6-month or longer delays not uncommon.

¹³ See, for example, Figure 1.3 on page 6 of RTEP02.

This suggests a high probability of continued congestion at least through the spring.

- The ISO's experience with new unit availability has also been instructive. New units generally experience much higher unavailability than established, similar units. While the ISO's economic analysis discussed above attempts to account for this, it likely understates the impact as it simply derates the new units for all hours rather than showing it to be fully unavailable during some periods.
- ISO planning studies continue to show economic and/or reliability needs in NEMA/Boston. RTEP02, cited earlier, is one example. Another is a series of studies presented to the New England Transmission Expansion Advisory Committee (TEAC) as part of TEAC 14 (held January 23, 2003) that identifies many needed units in the NEMA/Boston area and transmission upgrades required before some of these units may be retired.
- Finally, as noted below, if an area is identified as a DCA and no congestion occurs, the DCA Thresholds are irrelevant.

For these reasons, the ISO feels that it is appropriate that NEMA/Boston be a DCA despite the possibility of reduced congestion occurring in the future..

The identification of Nor/Stam as a reliability problem in each report, while the calculated number of congested hours does not appear to be significant, is worth discussion. Nor/Stam faces reliability problems in the event of a second contingency. There are insufficient resources in the sub-areas to adequately recover from such an event under some scenarios. However, it is not inconsistent that absent such a contingency, the area does not face significant congestion. That is, as long as all resources and transmission lines are available, congestion is minimal. But if certain outages occur, the system quickly becomes congested and vulnerable to blackout. The reliability studies highlight the delicate nature of the power system in Nor/Stam, while the congested hours show that under normal conditions the system allows adequate transfer of economic power. This makes DCA determination for Nor/Stam less clear-cut than for other areas.

Finally, it is worth noting that if an area designated as a DCA does not experience congestion, the DCA threshold would be expected to be irrelevant. In an unconstrained area, competition from outside the DCA would be expected to restrain suppliers within the DCA from offering above marginal costs near the DCA threshold. Thus, maintaining an area as a DCA when it is no longer congested, should not result in a different market outcome. In any event, the ISO may terminate a DCA at any time when it determines that the DCA designation is no longer warranted.

Congested Hours Used in Threshold Calculation

Market Rule 1, Appendix A provides upper and lower bounds of 2000 and 500 hours on the number of congested hours to be used in the DCA threshold calculation. As Tables 6

and 7 show, applying these bounds to the number of hours calculated using each method makes the method appear similar, and produces generally consistent results across years.

**Table 7
Congested Hours in Threshold Calculation by Method and DCA for FY 2001**

Method	NEMASS/Boston	CT	SWCT	Nor/Stam
Approach 1	2000	2000	2000	N/A
Approach 2	2000	1829	1527	N/A
Approach 3	2000	2000	1226	N/A
Approach 4	2000	2000	1505	N/A

**Table 8
Approach 4 Calculation Of Constrained Hours By Sub-Area-FY1999-FY2001**

	CT	SWCT	NOR/STAM	NEMASS/BOSTON
FY 2001	2000	1,505	N/A	2000
FY 2000	2000	2,000	N/A	2000
FY 1999	2000	1,309	N/A	2000

Only SWCT shows variation across years when the 2000 hour bound is applied.

VII. Conclusions

Of the four approaches used, each suggests that NEMASS/Boston, CT, and SWCT should be identified as DCAs. Nor/Stam does not merit selection based on a relatively limited number of congested hours calculated using Approach 4, though reliability studies consistently show that as a problem area. Northwest Vermont was not evaluated in this report because of data limitations.

The different approaches each produce somewhat different numbers of constrained hours. However, when the calculations are combined with the bounds on the threshold calculation contained in the rule, the differences across approaches are modest. Only in SWCT do the effective number of hours vary significantly. This consistency of results limits the impact of choosing any one approach. The impact of the difference between 2000 and 1500 constrained hours, in the threshold calculation, is expected to be on the order of \$15/MWh based on previous ISO estimates.

Exhibit 1

Units which can support the interfaces Conn, S W Conn and NEMASS&BOST

Interface	Unit Name	Interface	Unit Name	Interface	Unit Name
CONN	Aes Thames	S W CONN	Branford 10	NEMASS&BOST	Blackstone 1
CONN	Berkshire Power	S W CONN	Bridgeport Harbor 2	NEMASS&BOST	Framingham Jet 1
CONN	Bristol Refuse	S W CONN	Bridgeport Harbor 3	NEMASS&BOST	Framingham Jet 2
CONN	Cdecca	S W CONN	Bridgeport Harbor 4	NEMASS&BOST	Framingham Jet 3
CONN	Dexter	S W CONN	Bridgeport Energy 1	NEMASS&BOST	Kendall 1
CONN	Exeter	S W CONN	Bridgeport Resco	NEMASS&BOST	Kendall 2
CONN	Falls Village	S W CONN	Bulls Bridge	NEMASS&BOST	Kendall 3
CONN	Franklin Drive 10	S W CONN	Cos Cob 10	NEMASS&BOST	Kendall Ct
CONN	Lisbon Resource Recovery	S W CONN	Cos Cob 11	NEMASS&BOST	Kendall Jet 1
CONN	Middletown 1	S W CONN	Cos Cob 12	NEMASS&BOST	Kendall Jet 2
CONN	Middletown 10	S W CONN	Derby Dam	NEMASS&BOST	Kendall Steam
CONN	Middletown 2	S W CONN	Devon 10	NEMASS&BOST	L Street Jet
CONN	Middletown 3	S W CONN	Devon 11	NEMASS&BOST	M Street Jet
CONN	Middletown 4	S W CONN	Devon 12	NEMASS&BOST	Mystic 4
CONN	Millstone Point 2	S W CONN	Devon 13	NEMASS&BOST	Mystic 5
CONN	Millstone Point 3	S W CONN	Devon 14	NEMASS&BOST	Mystic 6
CONN	Montville 10 And 11	S W CONN	Devon 7	NEMASS&BOST	Mystic 7
CONN	Montville 5	S W CONN	Devon 8	NEMASS&BOST	Mystic 8
CONN	New Haven Harbor	S W CONN	Norwalk Harbor 1	NEMASS&BOST	Mystic 9
CONN	Montville 6	S W CONN	Norwalk Harbor 10 (3)	NEMASS&BOST	Mystic Jet
CONN	Norwich Jet	S W CONN	Norwalk Harbor 2	NEMASS&BOST	New Boston 1
CONN	Rainbow	S W CONN	PPL Wallingford Unit 1	NEMASS&BOST	Resco No. Andover
CONN	Secrec-Preston	S W CONN	PPL Wallingford Unit 2	NEMASS&BOST	Resco Saugus
CONN	So. Meadow 11	S W CONN	PPL Wallingford Unit 3	NEMASS&BOST	Salem Harbor 1
CONN	So. Meadow 12	S W CONN	PPL Wallingford Unit 4	NEMASS&BOST	Salem Harbor 2
CONN	So. Meadow 13	S W CONN	PPL Wallingford Unit 5	NEMASS&BOST	Salem Harbor 3
CONN	So. Meadow 14	S W CONN	Rocky River	NEMASS&BOST	Salem Harbor 4
CONN	So. Meadow 5	S W CONN	Shepaug	NEMASS&BOST	Waters River Jet 1
CONN	So. Meadow 6	S W CONN	SNEW #1	NEMASS&BOST	Waters River Jet 2
CONN	Torrington Terminal 10	S W CONN	SNEW #2 & 4	NEMASS&BOST	West Medway Jet 1
CONN	Tunnel 10	S W CONN	SNEW #3 & 5	NEMASS&BOST	West Medway Jet 2
CONN	Wallingford Refuse	S W CONN	SNEW #6		
		S W CONN	Stevenson		

Exhibit 2

Area	Month	Threshold Calculations			Heat Rate	Fuel Costs	Local Fuel Distribution Cost	VO&M	Net Annual Fixed Cost	Monthly Fixed Cost per Append A	Estimated ICAP	Other Market Revenues	Annual Constrained Hours
		Designated Congestion Area Threshold	Incremental Proxy CT Operating Cost	(Net Annual Fixed Cost)/(Annual Constrained Hours)									
		\$/MWh	\$/MWh	\$/MWh	Btu/kWh	\$/MMBtu	\$/MMBtu	\$/MWh	\$/MW-yr	\$/kW-mo	\$/kW-mo		Hours
CONN	January	-	-	\$32.40	10,500			\$3.00	\$64,800	\$6.15	\$0.75	0	2000
CONN	February	\$86.63	\$54.23	\$32.40	10,500	\$4.73	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
CONN	March	\$85.15	\$52.75	\$32.40	10,500	\$4.59	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
CONN	April	\$82.35	\$49.95	\$32.40	10,500	\$4.32	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
CONN	May	\$81.92	\$49.52	\$32.40	10,500	\$4.28	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
CONN	June	\$81.31	\$48.91	\$32.40	10,500	\$4.22	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
CONN	July	\$81.82	\$49.42	\$32.40	10,500	\$4.27	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
CONN	August	\$82.10	\$49.70	\$32.40	10,500	\$4.30	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
CONN	September	\$81.59	\$49.19	\$32.40	10,500	\$4.25	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
CONN	October	\$83.02	\$50.62	\$32.40	10,500	\$4.39	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
CONN	November	\$85.83	\$53.43	\$32.40	10,500	\$4.65	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
CONN	December	\$93.66	\$61.26	\$32.40	10,500	\$5.40	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
SWCT	January	-	-	\$35.06	10,500		\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	1848
SWCT	February	\$89.30	\$54.23	\$35.06	10,500	\$4.73	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	1848
SWCT	March	\$87.82	\$52.75	\$35.06	10,500	\$4.59	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	1848
SWCT	April	\$85.01	\$49.95	\$35.06	10,500	\$4.32	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	1848
SWCT	May	\$84.59	\$49.52	\$35.06	10,500	\$4.28	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	1848
SWCT	June	\$83.98	\$48.91	\$35.06	10,500	\$4.22	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	1848
SWCT	July	\$84.48	\$49.42	\$35.06	10,500	\$4.27	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	1848
SWCT	August	\$84.77	\$49.70	\$35.06	10,500	\$4.30	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	1848
SWCT	September	\$84.25	\$49.19	\$35.06	10,500	\$4.25	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	1848
SWCT	October	\$85.69	\$50.62	\$35.06	10,500	\$4.39	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	1848
SWCT	November	\$88.50	\$53.43	\$35.06	10,500	\$4.65	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	1848
SWCT	December	\$96.33	\$61.26	\$35.06	10,500	\$5.40	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	1848

Threshold Calculations												
	Designated Congestion Area Threshold	Incremental Proxy CT Operating Cost	(Net Annual Fixed Cost)/ (Annual Constrained Hours)	Heat Rate	Fuel Costs	Local Fuel Distribution Cost	VO&M	Net Annual Fixed Cost	Monthly Fixed Cost per Append A	Estimated ICAP	Other Market Revenues	Annual Constrained Hours
NEMA/Boston January	-	-	\$32.40	10,500		\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
NEMA/Boston February	\$86.63	\$54.23	\$32.40	10,500	\$4.73	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
NEMA/Boston March	\$85.15	\$52.75	\$32.40	10,500	\$4.59	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
NEMA/Boston April	\$82.35	\$49.95	\$32.40	10,500	\$4.32	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
NEMA/Boston May	\$81.92	\$49.52	\$32.40	10,500	\$4.28	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
NEMA/Boston June	\$81.31	\$48.91	\$32.40	10,500	\$4.22	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
NEMA/Boston July	\$81.82	\$49.42	\$32.40	10,500	\$4.27	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
NEMA/Boston August	\$82.10	\$49.70	\$32.40	10,500	\$4.30	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
NEMA/Boston September	\$81.59	\$49.19	\$32.40	10,500	\$4.25	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
NEMA/Boston October	\$83.02	\$50.62	\$32.40	10,500	\$4.39	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
NEMA/Boston November	\$85.83	\$53.43	\$32.40	10,500	\$4.65	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000
NEMA/Boston December	\$93.66	\$61.26	\$32.40	10,500	\$5.40	\$0.15	\$3.00	\$64,800	\$6.15	\$0.75	0	2000

Gas Price Calculations	Henry Hub - New England Basis \$/MMBtu difference	Henry Hub Futures \$/MMBtu futures average	New England \$/MMBtu 2003 monthly
January	0.412796		
February	0.331845	4.397365	4.729210
March	0.298118	4.290413	4.588531
April	0.245889	4.075397	4.321286
May	0.279731	4.001190	4.280922
June	0.214833	4.007762	4.222595
July	0.244140	4.026722	4.270862
August	0.260323	4.037770	4.298092
September	0.227167	4.021476	4.248643
October	0.364086	4.021587	4.385673
November	0.467889	4.185056	4.652944
December	1.072278	4.326563	5.398841