



Operating Procedures

ISO New England Operating Procedure No. 14

*Technical Requirements for Generators,
Demand Resources and Asset Related Demands*

Effective Date: September 9, 2011
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References:

1. ISO New England - ISO New England Inc. Transmission, Markets and Services Tariff Section III, ISO New England Market Rule 1 - Standard Market Design (Market Rule 1)
2. ISO New England Manual for Market Operations Manual M-11 (Manual 11)
3. ISO New England Manual for Forward Capacity Market Manual M-20 (Manual 20)
4. ISO New England Operating Procedure No. 1 - Central Dispatch Operating Responsibility and Authority of ISO New England, the Local Control Centers and Market Participants (OP-1)
5. ISO New England Operating Procedure No. 2 - Maintenance of Communications, Computers, Metering and Computer Support Equipment (OP-2)
6. ISO New England Operating Procedure No. 3 - Transmission Outage Scheduling (OP-3)
7. ISO New England Operating Procedure No. 4 - Action During a Capacity Deficiency (OP-4)
8. ISO New England Operating Procedure No. 5 - Generator and Dispatchable Asset Related Demand Maintenance and Outage Scheduling (OP-5)
9. ISO New England Operating Procedure No. 8 - Operating Reserve and Regulation (OP-8)
10. ISO New England Operating Procedure No.11 - Black Start Capability Testing Requirements (OP-11)
11. ISO New England Operating Procedure No. 12 - Voltage and Reactive Control (OP-12)
12. ISO New England Operating Procedure No. 16 - Transmission System Data (OP-16)

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13. ISO New England Operating Procedure No. 18 - Metering and Telemetry Criteria (OP-18)
14. Master Local Control Center Procedure No. 8 - Coordination of Generator Voltage Regulator and Power System Stabilizer Outages (M/LCC 8)
15. Master Local Control Center Procedure No. 10 - Generator Governor Control and Operation (M/LCC 10)
16. ISO New England Tariff
17. NPCC Regional Reliability Reference Directory # 2 - Emergency Operation (NPCC Directory #2)
18. NPCC Regional Reliability Reference Directory # 4 - Bulk Power System Protection Criteria (NPCC Directory #4)
19. NPCC Regional Reliability Reference Directory #12 – Under frequency Load Shedding Program Requirements (NPCC Directory #12)
20. North American Electric Reliability Corporation (NERC) Reliability Standards
21. Participants Agreement
22. Transmission Operating Agreement
23. Merchant Transmission Operating Agreements

Appendices:

1. Appendix A - Generator Technical Data
2. Appendix B - Generator Reactive Data
3. Appendix C - Annual/Monthly/Holiday Availability Requirements of Demand Response Loads
4. Appendix D - Resources Requiring Communications Independent of the Public Switched Network
5. Appendix E - Asset Related Demands Technical Data
6. Appendix F – Wind Plant Operators Guide

I. INTRODUCTION

A. BACKGROUND

This Operating Procedure (OP) describes the minimum technical requirements for Generator, Demand Response, and Asset Related Demands (ARDs) resources under the control of ISO New England Inc. (ISO). This OP addresses technical requirements, and not the Offer Data associated with these resources for submission to the Market, that may include parameters of a technical nature. This OP is meant to assure, in conjunction with the market structures that the Bulk Electric System (BES) of the New England Reliability Coordinator Area/Balancing Authority Area (RCA/BAA) conforms to proper standards of reliability. This OP is also meant to establish technical requirements to ensure that each Generator, Demand Resource and ARD has accurate metered data available for ISO dispatch control and Settlement.

B. STANDARDS

Compliance with all applicable ISO Operating Procedures (OPs) is the responsibility of all Market Participants (MPs). MPs must also comply with all applicable Northeast Power Coordinating Council Inc. (NPCC) and North American Electric Reliability Corporation (NERC) requirements. It is also expected that all elements specified in this OP will be operated utilizing Good Utility Practice including making resources available for service as soon as possible after failures of equipment.

II. TECHNICAL REQUIREMENTS FOR GENERATING UNITS

This section describes the basic technical requirements that a Generator must meet to be considered in the offer process. However, Generators must meet the eligibility requirements of ISO New England - ISO New England Inc. Transmission, Markets and Services Tariff Section III, ISO New England Market Rule 1 - Standard Market Design (Market Rule 1) and ISO Manuals to offer into the Markets.

Requirements outlined in sections C.4 and D.1 shall be implemented no later than June 1, 2011 unless agreed to by ISO New England on a case by case basis based on a demonstration that there is good cause to allow for a delay in implementation for a specified period, and the DE has demonstrated to the ISO's satisfaction that DE staff will be sufficiently alerted to Emergency Dispatch Instructions (Dispatch Instructions accompanied by an Emergency Message) prior to the full implementation of these requirements.

A. GENERATOR DEFINED

1. A Generator must be defined consistently for all ISO applications. That is, it must be defined in the same manner for the purposes of offers, dispatch and Settlement. In the case of a Generator that is a composite of multiple physical generating units, only the defined Generator will be represented, acted upon or allowed to transact in the various Markets. In all such cases, the Generator shall communicate with ISO through its Designated Entity (DE) registered in accordance with ISO Manuals and Administrative Procedures.
2. A defined Generator, composed of multiple generating units, is anticipated in the case of multi-unit hydro stations and most combined cycle units. A Market Participant (MP) right to combine physical generating units to create a Generator for bidding, dispatch and Settlement is governed by the following rules:
 - Generating units being combined must either be at the same physical site or be part of a project that, by its technical nature, requires coordinated control of the various units being combined to form a Generator
 - An MP may combine generating units to form a defined Generator of up to five (5) MW subject to the below Section C - Communication and Control
 - ISO will determine if generating units located on different electrical buses may be combined and defined as a Generator
 - ISO will consider if such a combination of generating units interferes with effective control of probable constraints or accurate determination of system losses, Operating Reserve and Regulation capabilities. The appropriateness of these combinations will be reviewed on a

continuing basis

- A defined Generator shall not be considered exempt from the requirement that an ISO Communications Front End (CFE) connected Remote Terminal Unit (RTU), all together referred to as ISO connected RTU, control no more than five (5) generating units without the review and approval of ISO

3. A generating unit of less than five (5) MW and that does not meet telemetering requirements per ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria (OP-18) or is less than 1 MW¹ and is therefore not represented in the ISO Energy Management System (EMS), has the following options:

- Registering as a “Settlement Only Generator”, which is eligible to participate in the Forward Capacity Market, and in the Energy Market according to MWh generated
- Treating the unit as a load reducer, in which case the unit is not registered with ISO and has no direct Capacity Supply Obligation (CSO) for an Forward Capacity Market (FCM) commitment period or other market settlement implications
- A unit is considered a less than five (5) MW unit if the annual average of its seasonal (summer or winter) ratings, or its rating in any month (for a daily cycle hydro or wind unit), as determined in accordance with ISO New England Manual for Forward Capacity Market Manual M-20 , is less than 5 MW

4. Offers may only be submitted for a defined Generator.

5. ISO will only perform Settlement functions for a defined Generator, and for units less than five (5) MW that do not meet OP-18 telemetering requirements and are treated as “Settlement Only Generators”.

6. To define a Generator, the MP is required to submit any technical data with respect to a Generator that ISO determines to be necessary for ISO to carry out its responsibility of reliably and efficiently operating the power system. The MP is required to submit the technical data for each physical component of a unit irrespective of whether it is modeled as a single unit or as multiple aggregations of the physical components of the unit, such as the case with some hydro units and combined cycle units. The MP is responsible

¹ A unit must be considered a less than one (1) MW unit if either its summer or winter capability is less than one (1) MW, or its rating in any month (for a daily cycle hydro or wind unit) is less than one (1) MW

for submitting and maintaining all requested data. The technical data includes, but is not limited to, the following:

- Generator Technical Data per Appendix A of this Procedure
- Form NX-12D, Generator Reactive Data, per Appendix B of this OP and as summarized in Appendix B of ISO New England Operating Procedure No. 12, Voltage and Reactive Control (OP-12)
- NX-9 data per ISO New England Operating Procedure No. 16, Transmission System Data (OP-16)
- Form NX-9B, Transformer-fixed/GSU/TCUL per OP-16
- Form NX-9D, Capacitor/Reactor per OP-16
- Station one-line diagrams

7. Equipment Requirements:

- Telemetry as defined by OP-18
- For Generators that are participating in the Market and/or are dispatchable in Real-Time, communications equipment, hardware and software sufficient to enable the DE to receive, acknowledge receipt, and implement ISO Dispatch Instructions electronically and, if necessary, verbally in a timely manner as required by ISO Manuals and Administrative Procedures. The points of contact between ISO and each DE for verbal Dispatch Instructions shall not exceed the number of ISO CFE connected RTUs installed for receipt of electronic Dispatch Instructions without prior approval of ISO. Participation in the Energy Market and Reserve Markets is conditioned upon having Electronic Dispatch Capability (EDC) installed. EDC is the ability, through the installation and maintenance of adequate hardware and software and communications infrastructure within the New England RCA/BAA, to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of Generators to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Generators. Generators are considered to have EDC when they are capable of receiving, responding to, and changing output in response to electronic Dispatch Instructions issued to the ISO CFE connected RTU of its DE.
- If the DE is not the entity that has direct operational control of a Generator, it is the responsibility of the DE in the event of a failure of the ISO CFE connected RTU or the failure of communications or other equipment between the ISO CFE connected RTU and the Generators connected to the ISO CFE connected RTU, to convey the Dispatch

Instructions issued by ISO to the generating unit(s) impacted by the equipment failure within the time and other constraints established by ISO Manuals and OPs, and to diligently pursue the repair and/or replacement of failed facilities owned by the DE on an expedited basis

8. To define a new Generator, a minimum of one hundred and twenty (120) days advance notice to ISO is required. To change data for an existing Generator definition, a minimum of seven (7) days advance notice to ISO is required. The advance notice period commences upon ISO receipt of the criteria detailed in Section II.A.6 of this OP.

9. Whenever a Lead MP wishes to change from one DE to another DE that already meets the technical requirements for receipt and acknowledgment and timely implementation of Dispatch Instructions as required by ISO Manuals and Administrative Procedures, said Lead MP shall provide at least thirty (30) days notice to ISO and shall cooperate with ISO and the current and proposed DEs to coordinate the transition from one DE to another.

10. Each Lead MP wishing to change from a DE to a proposed DE that does not yet meet the technical requirements referred to above shall provide ISO at least ninety (90) days notice of the proposed establishment of a DE as provided below and the transfer shall not become effective until such time as the new DE is in place. ISO and the Lead MP will cooperate to affect the transfer as rapidly as practical under the circumstances at the time a request is made.

11. Whenever a new DE is proposed to be created, the Lead Market Participant shall provide ISO no less than ninety (90) days prior written notice of the proposed establishment of a DE and shall cooperate fully with ISO in verifying that the proposed DE is fully capable of complying and has agreed to comply with all requirements imposed upon each DE or upon each MP acting by and through a DE under the Participants Agreement, the ISO New England Tariff, Market Rule 1, Manuals, Information Policy, these OPs, and any other document or requirement binding upon the MP to the same extent as if the MP were itself carrying out the functions of the DE and as fully as if each and every one of those requirements were fully set forth in this OP. ISO and the Lead Market Participant will cooperate to affect the transfer as rapidly as practical under the circumstances at the time a request is made.

12. No MP or Entity shall be recognized as a DE unless it has been registered pursuant to ISO Manuals and Administrative Procedures or meets the default provisions of said Manuals and Procedures.

13. No DE shall control more than five (5) generating units with a single ISO CFE connected RTU (whether or not part of a single defined Generator) without the review and prior written approval of the ISO.

B. TELEMETERING AND REVENUE METERING

1. Telemetry for the Generator must meet the requirements for speed and accuracy per OP-18. Telemetry must be maintained and calibrated by the MP on an ongoing basis per OP-18.
2. Revenue metering must meet ISO accuracy requirements per OP-18. Meter readings must be forwarded to ISO for Settlement, in a timely manner, as required per ISO Manuals and Administrative Procedures. The MP is responsible for the maintenance and calibration of revenue metering per ISO requirements as contained in OP-18.
3. Metering requirements for units less than five (5) MW will depend on their modeling option in the EMS and Market Systems:
 - Each Unit greater than one (1) MW that is represented in the EMS and Market Systems must meet the telemetry and revenue metering requirements described in II.B.1 and II.B.2 above
 - Each Unit that registers as a “Settlement Only Generator” must meet the revenue metering requirements described in II.B.2 above
 - Each Unit that is treated as a load reducer does not need telemetry

C. COMMUNICATION AND CONTROL

1. Any control equipment used to start, stop or vary the output of the Generator, from a remote location, must meet the requirements set in OP-18, relative to speed, accuracy and data channel requirements. Such equipment must be maintained by the MP according to ISO requirements contained in OP-18 and ISO New England Operating Procedure No. 2 - Maintenance of Communications, Computers, Metering and Computer Support Equipment (OP-2). ISO System Operators must be notified as soon as practicable if the equipment is incapable of meeting the requirements of OP-18. Steps should be taken to restore the equipment to normal operating conditions as soon as possible in accordance with OP-2.
2. Each DE must have a dedicated voice communication telephone for ISO dispatching purposes unless otherwise agreed on a case-by-case basis by ISO.

In addition to the dedicated voice communication telephone circuit, a DE for a dispatchable Generator fifty (50) MW or larger, and a Generator providing Regulation, are required to have a dedicated Auto Ring Down telephone circuit to the ISO Control Room unless otherwise agreed on a case-by-case basis by ISO.

Further, certain Generators are critical to the Bulk Electric System under emergency conditions. These Generators are listed in Appendix D of this OP and are required to install, maintain, operate, test and fund a voice

communications system that is independent of the public switched network for the purposes of communicating with its Local Control Center (LCC) during system emergencies such as a system restoration event. The installation, maintenance, testing and operation of the communications system must be coordinated with, and acceptable to, the Generator's LCC. Each LCC is responsible in turn for providing the requirements for the communications system and coordinating with each Generator to effect the installation, maintenance, operation and testing of the communications systems.

3. Each DE for a Generator that participates in the ISO Markets is required to have equipment capable of reliably receiving and acknowledging receipt of Dispatch Instructions sent electronically by ISO as frequently as necessary and to implement Dispatch Instructions in a timely manner as required by ISO Manuals and Administrative Procedures.

4. Each DE is required to display to their Generator Operator, or designee, the following parameters from their RTU for each dispatchable Generator, as defined in section II.A.7 of this OP, in New England that is under their responsibility.

- ACK Required (i.e. Acknowledgement Required)
- Message Type
 - (1) Normal
 - (2) Emergency
 - (3) Start Up
 - (4) Shut Down
- DDP
- Actual Generation
- Economic Minimum Limit
- Economic Maximum Limit
- Emergency Minimum Limit
- Response Rate
- Regulation High Limit (where applicable)
- Regulation Low Limit (where applicable)
- Unit Control Mode
- Heartbeat

5. Each DE is required to maintain staff on duty to communicate with ISO System Operators at all times.

6. In instances where Dispatch Instructions or any other orders must be issued verbally by ISO System Operators, the verbal communication shall take precedence over all other forms of communication.

D. EMERGENCY MESSAGE INDICATIONS

1. Emergency messages shall be displayed to each DE with visual and audible indications

- Each Generator must have a specific Message Type indicator.
- Each DE must not employ visual messages that are common to multiple Generators.
- Emergency messages must have an audible alarm that is unique to Emergency messages and cannot be disabled.
- Emergency messages are Message Type 2 (Emergency)
- Messages that require acknowledgement have an ACK Required = 1 on the RTU.

E. DISPATCH INSTRUCTIONS

1. All Dispatch Instructions (Includes Normal and Emergency)

- If a DE is not capable of controlling the delivery of energy in accordance with its Offer Data, the DE is required to notify the ISO System Operators as soon as practicable. Efforts should be made to forecast Generator capabilities based on daily local conditions and submit those parameters appropriately.

2. Normal Dispatch Instructions

- Normal Dispatch Instructions are transmitted electronically to each DE every five minutes or less, depending on system conditions.
- Manual acknowledgement of a Normal dispatch is not required, however compliance with the Dispatch Instruction is required in accordance with Offer Data without delay.
- Fast Start Generators will receive Start Up and Shut Down messages which must be acknowledged by the DE within 60 seconds. This acknowledgement requires physical action by staff at the DE. This item may be waived on a case by case basis by ISO New England. Acknowledgement of a Start Up or Shut Down message shall indicate

the DE intent to immediately comply with the Dispatch Instruction.

- Fast Start Generators shall not be shut down without receiving a Shut Down message. A Desired Dispatch Point (DDP) below the Economic Minimum Limit that is not accompanied by a Shut Down message is considered a dispatch to the Generator's Economic Minimum Limit.
- Under normal Dispatch Instructions, voice communications to ISO Control Room related to the Dispatch Instructions should be limited to only those pertaining to clarifying the Dispatch Instructions.

3. Emergency Dispatch Instructions

- Emergency messages will be issued by the ISO System Operators when an emergency issue requires an immediate response by Generators outside of the normal dispatch protocol.
- Emergency Dispatch Instructions are transmitted electronically to each DE every five minutes or less, depending on system conditions.
- Emergency messages shall be acknowledged manually within 60 seconds of the receipt of the message. This acknowledgement requires physical action by staff at the DE. This item may be waived on a case by case basis by ISO New England. Acknowledgement of the Emergency message shall indicate the DE intent to immediately comply with the Dispatch Instruction.
- Emergency Dispatch Instructions shall be followed in accordance with Offer Data without delay.
- In an emergency, off-line Fast Start Generators that are called on to start will receive an Emergency message and a non-zero DDP in lieu of a Start Up message. The DDP that accompanies the Emergency Message dictates the desired response from the Fast Start Generator. The DE must take action to ensure compliance with the Dispatch Instructions in accordance with their Offer Data.
- Fast Start Generators shall not be shut down without receiving a Shut Down message. A DDP below the Economic Minimum Limit that is not accompanied by a Shut Down message is considered a dispatch to the Generator's Economic Minimum Limit.
- Any generator providing Regulation when an Emergency message is received shall remove the Generator from Regulation and follow the DDP. Following an Emergency message, the Generator will not be placed on Regulation unless called for by ISO System Operators.
- While the Emergency message is active, voice communications to the ISO Control Room related to the Dispatch Instructions should be

limited to only those pertaining to clarifying the Dispatch Instructions.

F. OPERATIONAL CONSIDERATIONS

1. A Generator will be dispatched as directed by ISO in accordance with ISO New England Operating Procedure No. 1, Central Dispatch Operating Responsibility and Authority – ISO New England, the LCCs and Market Participants (OP-1), and the operating characteristics submitted by the MP. The safety of operating personnel and prevention of damage to equipment are the sole responsibility of the MP, and must take priority at all times.
2. Each Generator under five (5) MW that is treated as a “Settlement Only Generator” may elect to be dispatchable under ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency (OP-4) or may elect to Self-Schedule their energy.
3. Both the Planned and Maintenance Outages of the Generator will be done in accordance with ISO Generator maintenance scheduling procedures per ISO New England Operating Procedure No. 5, Generator and Dispatchable Asset Related Demand Maintenance and Outage Scheduling. (OP-5)
4. The MP must, at all times, comply with all applicable switching and tagging procedures in effect by the authorities governing switching and tagging operations in the field.

G. VOLTAGE CONTROL

1. The MVAR production of a Generator is an important factor in the reliable operation of the New England RCA/BAA. Each MP is to support system voltage and reactive needs at the direction of ISO and the LCC per OP-12. Each Generator in the New England RCA/BAA normally follows a schedule of bus voltages, which vary by load level (heavy/light) as contained in OP-12. ISO and the LCC have the authority to direct the MP to deviate from the normal voltage schedule to address operating situations. Each Generator is expected to participate, to the limit of their capability as documented in its NX-12D and as summarized in OP-12 Appendix B, to maintain their assigned voltage schedule as directed by ISO or the LCC and to comply with any variations that ISO or the LCC may request.
2. The MP must keep and maintain an automatic voltage regulator in the voltage regulation mode on all generating units comprising a Generator unless previously grandfathered or received exception under the Proposed Plan Application Process (I.3.9 process) for reliability purposes [Refer to Master/Local Control Center Procedure No. 8 Coordination of Generator Voltage Regulator and Power System Stabilizer Outages (M/LCC 8) Attachment A - Generators without an AVR and are Grandfathered]
3. It is the responsibility of each MP to maintain the voltage regulator in good operating condition and promptly report to ISO any problems that could cause interference with its proper operation. The MP must report to ISO if and

when the automatic voltage regulator is to be removed from or placed into service per M/LCC 8 prior to taking such action unless warranted by emergency plant conditions.

H. GOVERNOR CONTROL

Each MP is obligated to provide and maintain a functioning governor on each Generator with a capability of ten (10) MW or greater. The governor should be set in accordance with industry standards unless technical considerations dictate otherwise (governor droop set at five percent (5%)). If technical considerations dictate otherwise, the DE shall inform ISO per Master/Local Control Center Procedure No. 10 - Generator Governor Control and Operation (M/LCC 10). Each MP is responsible for periodic testing and maintenance of the Generator governor.

I. INTERCONNECTION

A Generator wishing to connect its facilities to transmission facilities must have a valid interconnection agreement(s) in place with the Transmission Owners(s) with which the Generator is wishing to interconnect, or whose facilities are impacted. The terms and conditions of said interconnection agreement(s) shall be negotiated between the entities that are parties to the interconnection agreement(s) and may or may not contain additional and/or more stringent requirements than those prescribed by ISO.

J. SYSTEM PROTECTION

1. At a minimum, each MP must install and maintain protection systems in accordance with the NPCC Regional Reliability Reference Directory # 4 - Bulk Power System Protection Criteria (NPCC Directory #4) on each unit that is large enough to affect the systems of others. Each MP is responsible for maintaining and upgrading the protection system such that it continues to meet the reliability criteria of NPCC.
2. Relay maintenance and testing that would in any way degrade the level of system protection or system reliability provided by the unit should not occur while the unit is on-line. All requests for such maintenance must adhere to the requirements of ISO New England Operating Procedure No. 3, Transmission Maintenance Outage Scheduling (OP-3), and local scheduling procedures at the lower voltage levels.
3. Under frequency relays for a unit must be set lower than under frequency relays used to disconnect customers for the purpose of balancing load and generation unless compensatory load shedding has been arranged for by the Generator Lead Market Participant. Section 5.4 of the NPCC Regional Reliability Reference Directory # 12, Under frequency Load Shedding Program Requirements (NPCC Directory #12), identifies the frequencies at which owners of generation can unilaterally disconnect from the power system.

K. POWER SYSTEM STABILIZERS

Where Power System Stabilizer (PSS) equipment is installed on a Generator for the purpose of maintaining system stability, it is the responsibility of the MP to maintain the PSS equipment in good operating condition, and promptly report to ISO any problems interfering with PSS proper operation. The MP should normally operate the PSS out of service unless directed otherwise per the unit's System Impact Study (SIS) or as directed by other studies as may be performed by ISO. A listing of Generators required to have a PSS in service can be found in M/LCC 8 Attachment B. Each MP must promptly report to ISO or the appropriate dispatch center, if and when the PSS is intended to be either placed into or removed from service prior to taking such action unless warranted by emergency plant conditions.

L. BLACK START CAPABILITY

Each MP that provides black start capability from one of their Generators and that Generator has been incorporated in the ISO or LCC system restoration plans and/or as defined by ISO New England Operating Procedure No. 11 - Black Start Capability Testing (OP-11) must maintain that Generator in good operating condition. Each MP must promptly report to ISO, or the appropriate dispatch center, any problems interfering with the black start capability of each such designated Generator.

M. ADDITIONAL REQUIREMENTS FOR WIND POWERED GENERATORS

Due to the unique nature and operating parameters associated with wind powered generation, additional specific requirements for these resources are necessary. Appendix F – Wind Plant Operators Guide details the criteria for wind powered generators and shall be used by Market Participants for interconnected operation. The requirements are in effect and become enforceable upon installation of the communications equipment necessary to perform the data transfer.

III. TECHNICAL REQUIREMENTS FOR DISPATCHABLE ASSET RELATED DEMANDS (DARDS)

This section describes the basic technical requirements that must be met by each DARD in order for it to be considered in the bidding process. However, each DARD must meet other eligibility requirements of Market Rule 1 and ISO Manuals to bid into the Markets.

Requirements outlined in sections C.4 and D.1 shall be implemented no later than June 1, 2011 unless agreed to by ISO New England on a case by case basis based on a demonstration that there is good cause to allow for a delay in implementation for a specified period, and the DE has demonstrated to the ISO's satisfaction that DE staff will be sufficiently alerted to emergency Dispatch Instructions (Dispatch Instructions accompanied by an Emergency Message) prior to the full implementation of these requirements.

A. DARDS

1. Each DARD must be defined consistently for all ISO applications. That is, it must be defined in the same manner for the purposes of bidding, dispatch and Settlement.
2. A bid may be submitted for only a defined DARD. Bid parameters for a DARD are submitted by the Lead Market Participant.
3. ISO will only perform Settlement functions for a defined DARD.
4. Each DARD is eligible to provide Operating Reserve in accordance with ISO New England Operating Procedure No. 8, Operating Reserve and Regulation (OP-8).
5. To define a DARD, each MP is required to submit any technical data with respect to a DARD that ISO determines to be necessary for ISO to carry out its responsibility to reliably and efficiently operate the power system. Each MP is responsible for submitting and maintaining all requested data. The technical data includes, but is not limited to, the following:
 - Dispatchable Asset Related Demand Technical Data, per Appendix E of this Procedure
 - NX-9 data as applicable, per OP-16
 - Form NX-9B as applicable, Transformer-fixed/GSU/TCUL, including each physical component, per OP-16
 - Form NX-9D as applicable, Capacitor/Reactor, including each physical component, per OP-16
6. Equipment Requirements:

- Telemetry as defined by OP-18
- Each DARD requires communications equipment, hardware and software, sufficient to enable the DE to receive, acknowledge receipt, and implement ISO Dispatch Instructions electronically and, if necessary, verbally in a timely manner as required by ISO Manuals and Administrative Procedures. The points of contact between ISO and each DE for verbal Dispatch Instructions shall not exceed the number of ISO CFE connected RTUs installed for receipt of electronic Dispatch Instructions without prior approval of ISO. Participation in the Energy Market is conditioned upon having Electronic Dispatch Capability (EDC) installed. EDC is the ability, through the installation and maintenance of adequate hardware and software and communications infrastructure within the New England RCA/BAA, to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of each DARD to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of each dispatchable DARD. Each DARD is considered to have EDC when it are capable of receiving, responding to, and changing output in response to electronic Dispatch Instructions issued to the ISO CFE connected RTU of its DE. Participation in the ISO Energy and Reserve Markets is conditioned upon having EDC installed
- If the DE is not the entity that has direct operational control of a DARD, it is the responsibility of the DE in the event of a failure of the ISO CFE connected RTU or the failure of communications or other equipment between the ISO CFE connected RTU and the each DARDs connected to the ISO CFE connected RTU, to convey the Dispatch Instructions issued by ISO to the DARD impacted by the equipment failure within the time and other constraints established by ISO Manuals and OPs, and to diligently pursue the repair and/or replacement of each failed facility owned by the DE on an expedited basis
- Communications equipment, hardware and software, sufficient to enable the DE to receive, acknowledge receipt, and implement ISO Dispatch Instructions electronically and, if necessary, verbally in a timely manner as required by ISO Manuals and Administrative Procedures. ISO may issue Dispatch Instructions as frequently as needed.

7. Each DARD definition must be submitted to ISO in accordance with the following advance notice requirements:

- To define a new DARD, a minimum of one hundred and twenty (120) days advance notice is required. The one hundred and twenty (120) day period commences upon ISO receipt of the criteria detailed in

Section III.A.5 of this OP

- To change the capability of an existing DARD, refer to ISO New England Manual for Forward Capacity Market Manual M-20 (Manual 20)

8. Whenever a Lead Market Participant wishes to change from one DE to another DE that already meets the technical requirements for receipt and acknowledgment and timely implementation of Dispatch Instructions as required by ISO Manuals and Administrative Procedures, said DARD owner shall provide at least thirty (30) days notice to ISO and shall cooperate with ISO and the current and proposed DEs to coordinate the transition from one DE to another.

Each Lead Market Participant wishing to change from a DE to a proposed DE that does not yet meet the technical requirements referred to above shall provide ISO at least ninety (90) days notice of the proposed establishment of a DE as provided below and the transfer shall not become effective until such time as the new DE is in place. ISO and the Lead Market Participant will cooperate to affect the transfer as rapidly as practical under the circumstances at the time a request is made.

Whenever a new DE is proposed to be created, the Lead Market Participant shall provide ISO no less than ninety (90) days *prior written* notice of the proposed establishment of a DE and shall cooperate fully with ISO in verifying that the proposed DE is fully capable of complying and has agreed to comply with all requirements imposed upon each DE or upon each MP acting by and through a Designated Entity under the Participants Agreement, the Tariff, Market Rule 1, ISO Manuals, ISO Information Policy, OPs, and any other document or requirement binding upon the MP to the same extent as if the MP were itself carrying out the functions of the DE and as fully as if each and every one of those requirements were fully set forth in this OP. ISO and the Lead Market Participant will cooperate to affect the transfer as rapidly as practical under the circumstances at the time a request is made.

B. TELEMETERING AND REVENUE METERING

1. Telemetering from each DARD must meet the requirements for speed and accuracy per OP-18. The MP is required to telemeter the instantaneous MW value of the DARD. Telemetering must be maintained and calibrated by the MP on an ongoing basis per OP-18.
2. Revenue metering must meet ISO accuracy requirements per OP-18 for all DARDs. Meter readings must be forwarded to ISO for Settlement in a timely manner as required per ISO Manuals and Administrative Procedures. The MP is responsible for the maintenance and calibration of revenue metering per ISO requirements as contained in OP-18.

C. COMMUNICATIONS AND CONTROL

1. Any control equipment used to start, interrupt, restore or vary the output of each DARD, from a remote location, must meet the requirements set in OP-18, relative to speed, accuracy and data channel requirements. Such equipment must be maintained by the MP according to ISO requirements contained in OP-18 and OP-2.

2. The DE of each DARD must have a dedicated voice communication telephone for ISO dispatching purposes unless otherwise agreed on a case-by-case basis by ISO.

In addition to the dedicated voice communication telephone circuit, the DE for of each DARD fifty (50) MW or larger, shall have a dedicated Auto Ring Down telephone circuit to the ISO Control Room unless otherwise agreed on a case-by-case basis by ISO.

3. Further, certain DARDs are critical to the Bulk Electric System under emergency conditions. These DARDs are listed in Appendix D of this OP and are required to install, maintain, operate, test and fund a voice communications system that is independent of the public switched network for the purposes of communicating with its LCC during system emergencies such as a system restoration event. The installation, maintenance, testing and operation of the system must be coordinated with, and acceptable to, the DARD LCC. Each LCC is responsible in turn for providing the requirements for the communications system and coordinating with the DARD owner to effect the installation, maintenance, operation and testing of the communication systems.

Each DE for a DARD that participates in ISO Markets is required to have equipment capable of reliably receiving and acknowledging receipt of Dispatch Instructions sent electronically by ISO as frequently as necessary and to implement Dispatch Instructions in a timely manner as required by ISO Manuals and Administrative Procedures. Each DARD is required to have equipment in place to reliably receive and carry out Dispatch Instructions received by their DE from ISO within the timing and other constraints required by ISO Manuals and Administrative Procedures.

4. Each DE is required to display to their operators the following parameters from their RTU for each DARD that is dispatchable, as defined in section III.A.6 of this OP, in New England and is under their responsibility:

- ACK Required (i.e. Acknowledgement Required)
- Message Type

- (1) Normal
 - (2) Emergency
 - (3) Start Up
 - (4) Shut Down
- DDP
 - Actual Consumption
 - Minimum Consumption Limit
 - Maximum Consumption Limit
 - Response Rate
 - Unit Control Mode
 - Heartbeat

5. Each DE is required to maintain staff on duty to communicate with ISO System Operators at all times.

6. In instances where Dispatch Instructions or any other orders must be issued verbally by ISO System Operators, the verbal communication shall take precedence over all other forms of communication.

D. EMERGENCY MESSAGE INDICATIONS

1. Emergency messages shall be displayed to each DE with visual and audible indications

- Each DARD must have a specific Message Type indicator.
- Each DE must not employ visual messages that are common to multiple assets.
- Emergency messages must have an audible alarm that is unique to Emergency messages and cannot be disabled.
- Emergency messages are Message Type 2 (Emergency).
- Messages that require acknowledgement have an ACK Required = 1 on the RTU.

E. DISPATCH INSTRUCTIONS

1. All Dispatch Instructions (Includes Normal and Emergency)

- If a DE is not capable of controlling the consumption of energy in accordance with its Offer Data, the DE is required to notify the ISO System Operators. Efforts should be made to forecast DARD

capabilities based on daily local conditions and submit those parameters appropriately.

2. Normal Dispatch Instructions

- Normal Dispatch Instructions are transmitted electronically to each DE every five minutes or less, depending on system conditions.
- Compliance with the Dispatch Instruction is required in accordance with Offer Data without delay. Dispatch Instructions below Minimum Consumption Limit or above Maximum Consumption Limit shall be followed at the discretion of the DE, in cooperation with ISO System Operators.
- Under Normal Dispatch Instructions, voice communications to the ISO Control Room related to the Dispatch Instructions should be limited to only those pertaining to clarifying the Dispatch Instructions.

3. Emergency Dispatch Instructions

- Emergency messages will be issued by the ISO System Operators when an emergency issue requires an immediate response by DARDs outside of the normal dispatch protocol.
- Emergency Dispatch Instructions are transmitted electronically to each DE every five minutes or less, depending on system conditions.
- Emergency messages shall be acknowledged manually within 60 seconds of the receipt of the message. This item may be waived on a case by case basis by ISO New England. This acknowledgement requires physical action by staff at the DE. Acknowledgement of the Emergency message shall indicate the DE intent to immediately comply with the Dispatch Instruction.
- Emergency Dispatch Instructions shall be followed in accordance with Offer Data without delay. Dispatch Instructions below Minimum Consumption Limit or above Maximum Consumption Limit shall be coordinated with the ISO System Operators.
- In an emergency, DARDs will receive an Emergency message in lieu of a Shut Down message. The DDP that accompanies the Emergency message dictates the desired response from the DARD. The DE must take action to ensure compliance with the Dispatch Instructions.
- While the Emergency message is active, voice communications to the ISO Control Room related to the Dispatch Instructions should be limited to only those pertaining to clarifying the Dispatch Instructions.

F. OPERATIONAL CONSIDERATIONS

1. Each DARD shall be dispatched as directed by ISO in accordance with OP-1, and the operating characteristics submitted by the MP. The safety of operating personnel and prevention of damage to equipment are the sole responsibility of the MP, and must take priority at all times.
 2. The MP is required to ensure the maintenance of the DARD control equipment in good operating condition, and must promptly report to ISO any problems interfering with its proper operation.
 3. Both the Planned and Maintenance Outages of DARDs will be done in accordance with ISO Generator maintenance scheduling procedures per OP-5.
- The MP must, at all times, comply with all applicable switching and tagging procedures in effect by the authorities governing switching and tagging operations in the field.

G. INTERCONNECTION

Each DARD wishing to connect its facility to transmission facilities must have a valid interconnection or Service agreement(s) in place with the Transmission Owners(s) with which the DARD is wishing to interconnect, or whose facilities are impacted. The terms and conditions of said interconnection agreement(s) shall be negotiated between the entities who are parties to the interconnection agreement(s) and may or may not contain additional and/or more stringent requirements than those prescribed by ISO.

IV. TECHNICAL REQUIREMENTS FOR ASSET RELATED DEMANDS (ARDS) (NOT DISPATCHABLE)

This section describes the basic technical requirements that must be met by each ARD.

A. ARDs (NOT DISPATCHABLE)

1. Each ARD must be defined consistently for all ISO applications. That is, it must be defined in the same manner for the purposes of bidding and Settlement.
2. ISO will only perform Settlement functions for a defined ARD.
3. To define an ARD, the MP is required to submit any technical data with respect to an ARD that ISO determines to be necessary for ISO to carry out its responsibility to reliably and efficiently operate the power system. Registration of an ARD will be subject to the provisions of Section I.3.9 of the ISO New England Transmission, Markets and Services Tariff to the extent that the operation of the proposed ARD may have a significant effect on the stability, reliability or operating characteristics of the New England RCA/BAA.

Each MP is responsible for submitting and maintaining all requested data. The technical data includes, but is not limited to, the following:

- Asset Related Demand Technical Data, per Appendix E of this OP
 - NX-9 data as applicable, per OP-16, Transmission System Data
 - Form NX-9B as applicable, Transformer-fixed/GSU/TCUL, including each physical component, per OP-16
 - Form NX-9D as applicable, Capacitor/Reactor, including each physical component, per OP-16
4. Equipment Requirements:
- Telemetry as defined by OP-18
5. ARD definitions must be submitted to ISO in accordance with the following advance notice requirements:
- To define a new ARD, a minimum of one hundred and twenty (120) days advance notice is required. The one hundred and twenty (120) day period commences upon ISO receipt of the criteria detailed in Section IV.A.3 of this OP
 - The ISO Manuals should be referenced to change the capability of an existing ARD

B. TELEMETERING AND REVENUE METERING

1. Telemetry from each ARD must meet the requirements for speed and accuracy per OP-18. The MP is required to telemeter the instantaneous MW value of an ARD. Telemetry must be maintained and calibrated by the MP on an ongoing basis per OP-18.
2. Revenue metering must meet ISO accuracy requirements per OP-18 for each ARD. Meter readings must be forwarded to ISO for Settlement in a timely manner as required per ISO Manuals and Administrative Procedures. The MP is responsible for the maintenance and calibration of revenue metering per ISO requirements as contained in OP-18.

C. INTERCONNECTION

An ARD wishing to connect its facility to transmission facilities must have a valid interconnection or service agreement(s) in place with the Transmission Owners(s) with which the ARD is wishing to interconnect, or whose facilities are impacted. The terms and conditions of said interconnection agreement(s) shall be negotiated between the entities who are parties to the interconnection agreement(s) and may or may not contain additional and/or more stringent requirements than those prescribed by ISO.

V. TYPES OF DEMAND RESOURCES

Active Demand Resources are comprised of interruptible loads. Interruptible loads are defined as any load or collection of loads which can be removed within a predetermined time period from the power system through the action (i.e. push button, telephone call, etc.) of a Demand Resource operator (Enrolling Participant), in response to instructions received and accepted through the ISO CFE connected RTU. There are two (2) active Demand Resource types available for real-time interruptible loads to register and participate in. A Demand Resource can only be registered as one (1) of these types. These Demand Resource types do not provide operating reserve, however, they are used by the ISO to maintain operating reserve or partially restore operating reserve on supply side resources as well as maintain transmission reliability within established criteria. It is recognized that Load Serving Entities (LSEs) may have particular programs under their control specifically to manage their load. The two active Demand Resource types are listed below and further explanation is provided.

Real-Time Demand Response Resource - 30 minutes or less notification

Real-Time Emergency Generation Resource - 30 minutes or less notification

A. REAL-TIME DEMAND RESPONSE RESOURCE – 30-MINUTES OR LESS NOTIFICATION

This Demand Resource type requires 30 minutes or less notification from ISO to interrupt. A Real-Time Demand Response Resource is interrupted by ISO during Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours as defined in Market Rule 1. A Real-Time Demand Response Resource can be activated on a zonal or system-wide basis. When a Real-Time Demand Response Resource is activated, ISO can dispatch the Real-Time Demand Response Resource to any reduction level of their obligation. All Real-Time Demand Response Resources in the same zone will be activated for an event on a pro-rata basis represented by the Real-Time Demand Response Resource obligation in that zone to the total Real-Time Demand Response Resource obligations in that zone. These Real-Time Demand Response Resource are eligible to qualify as an FCM Resource subject to the performance criteria identified within Market Rule 1 and the ISO manuals.

B. REAL-TIME EMERGENCY GENERATION RESOURCES – 30 MINUTE OR LESS NOTIFICATION

This Demand Resource type requires 30 minutes or less notification from ISO to interrupt, (interrupting load includes both reducing load by stopping a process or by shifting the load to a generator at the facility) and are composed of distributed generation resources that have environmental air permits that limit their operation to situations involving loss of external power or the imminent loss of external power. A Real-Time Emergency Generation Resource is interrupted by ISO during capacity deficiencies when OP-4 Actions activating manual voltage reduction requiring more than 10 minutes are implemented. A Real-Time

Emergency Generation Resource can be activated on a zonal or system-wide basis. When a Real-Time Emergency Generation Resource is activated, ISO can dispatch these resources to any reduction level of their obligation. All Real-Time Emergency Generation Resource in the same zone will be activated for an event on a pro-rata basis represented by the resource obligation in that zone to the total demand resources obligations in that zone. A Real-Time Emergency Generation Resource must be available for interruption during the period hour ending 0800 through hour ending 1900 on all non-holiday weekdays per Appendix C of this OP. A Real-Time Emergency Generation Resource is eligible to qualify as an FCM Resource subject to the performance criteria identified within Market Rule 1 and ISO manuals.

VI. TECHNICAL REQUIREMENTS FOR REAL-TIME DEMAND RESPONSE RESOURCES AND REAL-TIME EMERGENCY GENERATION RESOURCES

A. TECHNICAL REQUIREMENTS

This section describes the basic technical requirements that must be met by each Real-Time Demand Response Resource and Real-Time Emergency Generation Resources. Real-Time Demand Response Resources and Real-Time Emergency Generation Resources involves any load or collection of loads that are associated with an active Demand Resource that has a Capacity Supply Obligation for the current Capacity Commitment Period (the commitment period could be as little as a single month) which can be removed or supply energy, within a predetermined time period, through the action (i.e., push button, telephone call, etc.) of a power system operator. Real-Time Demand Response Resources and Real-Time Emergency Generation Resources are defined by the following:

1. A Real-Time Demand Response Resource and Real-Time Emergency Generation Resource must be defined in the same manner for the purposes of dispatch and Settlement. A Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource may include the following:
 - Individual or aggregated loads of end-use customers
 - Other operator controlled demand-reducing actions
2. A bid or offer is not submitted for a Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource.
3. A Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource must be not less than 100 kW.
4. ISO will perform Settlement functions for a Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource meeting the technical rules of this Section and in accordance with the ISO Manuals and Administrative Procedures.
5. To define a Real-Time Demand Response Resource and Real-Time Emergency Generation Resource, the MP is required to submit any technical data with respect to the resource that ISO determines to be necessary for ISO to carry out its responsibility to reliably and efficiently operate the power system. The MP is responsible for submitting and maintaining all requested data. The technical data includes, but is not limited to, the following:
 - Registration through the ISO Customer Asset Management System (CAMS) application which is accessible at <https://smd.iso-ne.com>

6. A Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource definition must be submitted to ISO in accordance with the following advance notice requirements:

- Seven (7) days advance notice is required to define a new Real-Time Demand Response Resource or change its definition. The seven (7) day period commences upon ISO receipt of the criteria detailed in Section VI.A.5 of this OP

7. Equipment Requirements:

- Telemetry as defined by OP-18
- A Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource requires communications equipment, hardware and software, sufficient to enable Demand Designated Entities (DDEs) to receive, and implement ISO Dispatch Instructions electronically and, if necessary, verbally in a timely manner as required by ISO Manuals and Administrative Procedures. Participation in the FCM for active DR is conditioned upon having communication systems installed meeting the communication requirements. Communication requirements provide the ability, through the installation and maintenance of adequate hardware and software and communications infrastructure within the New England RCA/BAA, to provide for the electronic transmission and receipt of data relative to the dispatch of a Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of a Real-Time Demand Response Resource and Real-Time Emergency Generation Resource. A Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource are considered to have met this requirement when they are capable of receiving, responding to, and changing output in response to electronic Dispatch Instructions issued to the ISO CFE connected RTU of its DDE. Participation in the FCM is conditioned upon having such capability installed
- If the DDE is not the entity that has direct operational control of a Real Time Demand Response Resource or Real-Time Emergency Generation Resource, it is the responsibility of the DDE in the event of a failure of the ISO CFE connected RTU or the failure of communications or other equipment between the ISO CFE connected RTU and the Real-Time Demand Response Resource and Real-Time Emergency Generation Resource connected to the ISO CFE connected RTU, to convey the Dispatch Instructions issued by ISO to the Real-Time Demand Response Resource and Real-Time Emergency Generation Resource impacted by the equipment failure

within the time and other constraints established by ISO Manuals and OPs, and to diligently pursue the repair and/or replacement of any failed facility owned by the DDE on an expedited basis

8. Whenever a Lead Market Participant wishes to change from one DDE to another DDE that already meets the technical requirements for receipt and timely implementation of Dispatch Instructions as required by ISO Manuals and Administrative Procedures, said Real Time Demand Response Resource or Real-Time Emergency Generation Resource owner will provide at least thirty (30) days notice to ISO and shall coordinate and comply with ISO and the current and proposed DDEs to transition from one DDE to another.

Lead Market Participants wishing to change from a DDE to a proposed DDE that does not yet meet the technical requirements referred to above will provide ISO at least ninety (90) days notice of the proposed establishment of a DDE as provided below and the transfer will not become effective until such time as the new DDE is in place.

Whenever a new DDE is proposed to be created, the Lead Market Participant will provide ISO no less than ninety (90) days **prior written** notice of the proposed establishment of a DDE. The Lead Market Participant and the ISO will coordinate to verify that the proposed DDE is fully compliant with all requirements of a DDE or upon MPs acting by and through a DDE under the Participants Agreement, the Tariff, Market Rule 1, ISO Manuals, ISO Information Policy, these OPs, and any other document or requirement binding upon the MP to the same extent as if the MP were itself carrying out the functions of the DDE and as fully as if each and every one of those requirements were fully set forth in this OP. ISO and the Lead Market Participant will cooperate to affect the transfer as rapidly as practical under the circumstances at the time a request is made.

B. TELEMETERING AND REVENUE METERING

1. Each DDE is required to telemeter the 5 minute load and or generation value of each Real-Time Demand Response Resource or Real-Time Emergency Generation Resource. Telemetering must be maintained and calibrated by the MP or their designee on an ongoing basis per OP-18. ISO does not specify how the DDE will communicate with or obtain telemetering data from the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource. However, the telemetering requirement for the DDE to provide data to ISO must meet the requirements for speed and accuracy per OP-18.

2. Revenue metering must meet ISO accuracy requirements per OP-18 for each Real-Time Demand Response Resource or Real-Time Emergency Generation Resource. Meter readings must be forwarded to ISO for Settlement in a timely manner as required per ISO Manuals and Administrative Procedures. The MP or their designee is responsible for the

maintenance and calibration of revenue metering per ISO requirements as contained in OP-18.

C. COMMUNICATIONS AND CONTROL

1. Any control equipment used to start, interrupt, restore or vary the output of Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, from a remote location, must meet the requirements set in OP-18, relative to speed and accuracy. Such equipment must be maintained by the MP or their designee according to ISO requirements contained in OP-18.

2. Each DDE must have a dedicated voice communication telephone for ISO dispatching purposes unless otherwise agreed on a case-by-case basis by ISO.

In addition to the dedicated voice communication telephone circuit, each DDE having five hundred (500) MW total of active Real-Time Demand Response Resources and Real-Time Emergency Generation Resource (measured in net CSO) or larger, is required to have a dedicated Auto Ring Down telephone circuit to the ISO Control Room unless otherwise agreed on a case-by-case basis by ISO.

Each DDE for a Real-Time Demand Response Resources or Real-Time Emergency Generation Resource are required to have equipment capable of reliably receiving and implementing Dispatch Instructions sent electronically by ISO as frequently as necessary and to implement Dispatch Instructions in a timely manner as required by ISO Manuals and Administrative Procedures. All Real-Time Demand Response Resource and Real-Time Emergency Generation Resource are required to have equipment in place to reliably receive and carry out Dispatch Instructions received by their DDEs from ISO within the timing and other constraints required by ISO Manuals and Administrative Procedures.

3. The Communications Infrastructure for Demand Resources must meet the requirements as detailed in OP-18.

D. OPERATIONAL CONSIDERATIONS

1. A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource will be interrupted when directed by ISO through the DDE, and implemented in accordance with the operating characteristics submitted by the MP.

2. The MP is required to insure that any Real-Time Demand Response Resource or Real-Time Emergency Generation Resource control equipment is maintained in good functional operation, and must promptly report to ISO any problems interfering with its proper operation.

E. INTERCONNECTION

A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource wishing to connect its facilities to transmission facilities must have a

valid interconnection agreement(s) (if required) in place with the Transmission Owners(s) with which the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is wishing to interconnect, or whose facilities are impacted. The terms and conditions of said interconnection agreement(s) shall be negotiated between the entities who are parties to the interconnection agreement(s) and may or may not contain additional and/or more stringent requirements than those prescribed by ISO. It should be noted that load does not necessarily require an interconnection agreement. In all cases the need is determined by the Transmission Owner.

VII. AUDITING AND TESTING

ISO reserves the right to conduct unannounced audits or tests of a DE, Generator, DARD, DDE, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource to verify its compliance with the technical requirements as set forth in this Procedure and in accordance with Market Rule 1. These audits may be conducted on a periodic basis or because ISO has a reason to suspect a deficiency. On site audits will be coordinated with the MP, DE, or DDE (as appropriate) and scheduled during normal business hours. For audit, it will be conducted according to:

ISO New England Manual for Market Operations Manual M-11,

ISO New England Manual for Registration and Performance Auditing M-RPA,

ISO Load Response Program Manual,

and ISO Measurement and Verification for Demand Resources Manual.

Failure to comply with the technical requirements of this OP may cause the Resource to be unable to perform in the Markets. This does not include compliance failures due to circumstances beyond the reasonable control of the MP, such as transmission, distribution or communications outages. ISO will determine the Generator, DARD, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource ability to perform in the Markets when not in compliance with the requirements of this OP. Failure to perform in the Markets is Sanctionable Behavior, and subject to treatment under Market Rule 1.

A. REVENUE METERING

ISO has the right to audit testing and calibration records, and order and witness the testing of revenue metering per OP-18. In the event that ISO-ordered testing results in metering tests occurring more frequently than once in a twelve (12) month period, ISO would pay for the reasonable expense of the extra meter testing only in the event that the metering system is found to be fully functional and in calibration per OP-18. When tested otherwise, the MP will be responsible for the expenses of the extra meter testing.

B. EQUIPMENT MAINTENANCE

Each MP shall keep detailed records of equipment maintenance. ISO shall have

the right to review the maintenance and test record for auditing purposes to insure that the equipment (voltage regulator, governor, stabilizer equipment, telemetering and communication and control equipment) is maintained in good operating condition.

C. PROTECTION SYSTEMS

ISO shall have the right to review protection studies, elementary diagrams, relay setting documents, relay maintenance reports and relay calibration records in order to audit compliance with the protection criteria of NPCC and ISO.

VIII. FORMS ADMINISTRATION

ISO Forms NX-12, 12D, 12E and NX-reside in the appendices to this OP. Each appendix also contains an explanation of terms and instructions for data preparation of the specific form. Send completed forms NX-12, 12D and 12E to the ISO New England Market Support Services Department at opanx12@iso-ne.com. ISO staff will then review the forms for completeness, and assign a data revision number to the form if required. Market Support Services shall also route completed forms NX-12, 12D and 12E to the ISO New England Power System Modeling & Support group for changes to the EMS. If additional or missing information is required, the ISO staff will contact the person who prepared the form to obtain the necessary information. Once ISO has determined the forms to be complete and accurate, the forms will be routed to the appropriate ISO departments.

IX. OP 14 REVISION HISTORY

Document History (This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well revisions made to the ISO New England Procedure subsequent to the RTO Operations Date.)

Rev. No.	Date	Reason
Rev 1	10/23/98	
Rev 2	05/20/99	
Rev 3	10/21/99	
Rev 4	12/05/00	
Rev 5	06/01/01	
Rev 6	01/10/03	
Rev 7	06/26/03	
Rev 8	02/20/04	
Rev 9	02/01/05	Updated to conform to RTO terminology
Rev 10	05/06/05	Update for NERC Version 0 Standards, Updated URL for LRP asset registration
Rev 11	10/01/06	Updated for ASM Phase 2
Rev 12	11/15/07	Revised for Pseudo Combined Cycle Generator Requirements
Rev 13	05/21/08	Corrected NPCC and NERC names in References Globally defined acronym for various frequently used terms (e.g., Designated Entity = DE, Market Participant = MP) and/or used acronyms that are defined in ISO Manuals to improve readability. Section II.A. 34th bullet moved as Footnote 2, Redundant language in that a less than 1 mw unit is also a less than 5 mw unit. Removed Footnote 1 to Section II.A.3. Comment was added in preparation for implementation of 05/01/1999 ISO-NE Interim Markets. With the implementation of the Interim Markets in 1999 and subsequent implementation of Standard Market Design in 2003, ISO-NE no longer has need to limit units of <1 MW from participation in the energy and capacity markets. Added Footnote 2 to Section II.A.3., Clarification that a Unit < 1 MW is not represented in the ISO Energy Management System Section II.A.7 and III.A.6, clarified current language, These changes remove language which is redundant with information already in the same sections for DARDs and Generators. The current language is not well understood nor in past or present practice Provided the definition for the acronym RIG Section II. A.7. 1 st bullet Corrected "power system operator" to now state "Demand Resource operator" and replaced "(LCC, MP)" with "(Enrolling Participant) in Section V.
Rev 14	06/01/10	Updated document for FCM changes including: elimination of existing DR programs and new DR FCM capacity, and RIG replacement with ISO CFE connected RTU.

Rev. No.	Date	Reason
Rev 15	03/04/11	Biennial Review by procedure owner; Global, editorial and format changes, font to Arial, added a Table of Contents, added uncontrolled disclaimer to 1 st page and all page footers, and replaced page numbers with Page X of Y format; Corrected Reference titles and added additional documents referred to in OP test; Moved Appendices list from after the TOC to be located directly after the References; Globally replaced “this Procedure” with “this OP”, defined commonly used terms with accepted/recognized acronyms at first use and used the acronyms for subsequent uses, replaced the use of Resource with the actual entity term, replaced the use of plural terms with singular terms to make directed actions and responsibilities clear, replaced “bulk power system” with “Bulk Electric System”, replaced Control Area with “Reliability Coordinator Area, corrected typographical errors, made grammar changes; Section II.A.7. 1 st bullet replaced “CFRE” with “CFE”; Section II.A.7 2 nd bullet, added “and Reserve Markets” and deleted “Participation in the ISO Energy and Reserve Markets is conditioned upon having EDC installed”; Section II C.1 added “ISO System Operators must be notified immediately if the equipment is incapable of meeting the requirements of OP-18. Steps should be taken to restore the equipment to normal operating conditions as soon as possible.”; Added new: Section II.C.4, Section II.C.5, Section II.D, Section II.E & Section II.F; Renamed former sections II.D through II.J as Sections II.G through II.M; Section II.K.3 Provided correct title for NPCC Directory #2; II.L defined acronym PSS; Section III.C added steps 4. & 5; Section III. D added new Section, Steps, and sub-steps; Section III.E added new Section Steps and bullets; Renamed former Sections III.D and E as new Sections III.F and G;
Rev 16	09/09/11	Section II, added new subsection M, “Additional Requirements for Wind Powered Generation, Added new Appendix F, Wind Plant Operators Guide