ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources

Effective Date: November 7, 2018

Table of Contents

References

1. ISO New England Inc. Transmission, Markets, and Services Tariff, Section I - General Terms and Conditions
2. ISO New England Inc. Transmission, Markets and Services Tariff, Section III - Market Rule 1 - Standard Market Design (Market Rule 1)
3. ISO New England Manual for Market Operations Manual M-11 (Manual 11)
4. ISO New England Manual for the Forward Capacity Market (FCM) Manual M-20 (Manual 20)
5. ISO New England Manual for Registration and Performance Auditing Manual M-RPA (M-RPA)
6. ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources Manual (M-MVDR)
7. ISO New England Operating Procedure No. 1 - Central Dispatch Operating Responsibilities and Authority (OP-1)
8. ISO New England Operating Procedure No. 2 - Maintenance of Communications, Computers, Metering and Computer Support Equipment (OP-2)
9. ISO New England Operating Procedure No. 3 - Transmission Outage Scheduling (OP-3)
10. ISO New England Operating Procedure No. 4 - Action During a Capacity Deficiency (OP-4)
11. ISO New England Operating Procedure No. 5 - Resource Maintenance and Outage Scheduling (OP-5)
12. ISO New England Operating Procedure No. 8 - Operating Reserve and Regulation (OP-8)
13. ISO New England Operating Procedure No.11 - Blackstart Resource Administration (OP-11)
14. ISO New England Operating Procedure No. 12 - Voltage and Reactive Control (OP-12)
15. ISO New England Operating Procedure No. 16 - Transmission System Data (OP-16)
16. ISO New England Operating Procedure No. 18 - Metering and Telemetering Criteria (OP-18)
17. Master/Local Control Center Procedure No. 1 - Nuclear Plant Transmission Operations (M/LCC 1)

18. Master/Local Control Center Procedure No. 8 - Coordination of Generator Voltage Regulator and Power System Stabilizer Outages (M/LCC 8)
19. Master/Local Control Center Procedure No. 10 - Generator Governor Control and Operation (M/LCC 10)
20. NPCC Regional Reliability Reference Directory # 2 - Emergency Operation (NPCC Directory #2)
21. NPCC Regional Reliability Reference Directory # 4 - Bulk Power System Protection Criteria (NPCC Directory #4)
22. North American Electric Reliability Corporation (NERC) Reliability Standards
23. North American Electric Reliability Corporation (NERC) Glossary of Terms Used in NERC Reliability Standards
24. Participants Agreement
25. Transmission Operating Agreements
26. Merchant Transmission Operating Agreements
27. ISO New England Compliance Bulletin - MOD-026, MOD-027 & Tariff Provision of Validated Dynamics Models to New England
28. ISO New England Compliance Bulletin - MOD-032 - Model Data Requirements and Reporting Procedures

Appendices

Appendix A - Explanation of Terms and Instructions for Data Preparation of ISO New England Form NX-12, Generator Technical Data

Appendix B - Generator Reactive Data Explanation of Terms and Instructions for Data Preparation for ISO Form NX-12D

Appendix C - Retired (06/27/18)

Appendix D - Resources Requiring Communications Independent of the Public Switched Network

Appendix E - Explanation of Terms and Instructions for Data Preparation of ISO New England Form NX-12E, Asset Related Demands Technical Data

Appendix F - Wind Plant Operator Guide

Appendix G - Explanation of Terms and Instructions for Data Preparation of ISO New England Form NX-12G, Alternative Technology Regulation Resource Technical Data

I. INTRODUCTION

A. Background

1. This Operating Procedure (OP) describes the minimum technical requirements for defined generator units described in Section II.A.2 of this OP which are referred to as “Generators” for purposes of this OP, Settlement Only Resources/Generators (SOGs), Demand Response Resources (DRRs), Asset Related Demands (ARDs) and Alternative Technology Regulation Resources (ATRRs) under the control/jurisdiction of ISO New England Inc. (ISO). For the purposes of this OP, “under the control/jurisdiction of ISO” is defined as:

   a. an individual or aggregated asset/resource/unit/facility classification meeting the technical criteria as stipulated in Sections II, III, IV, V or VI as applicable, or

   b. is participating in the wholesale electric market.

2. This OP addresses technical requirements, and **not** the Offer Data associated with these resources for submission to the New England Markets, 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)[1] 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 verify that each Generator, DR, DRR, ARD and ATRR has accurate metered data available for ISO dispatch control and settlement.

B. Standards

1. Compliance with all applicable ISO OPs is the responsibility of:

   (1) in the case of a Generator, the Lead Market Participant (Lead MP) for the Asset;

   (2) in the case of a DRR, the Lead MP for the DRR; and

   (3) in the case of an ATRR, the Lead MP for the ATRR.

   The Lead MP for the Asset (in the case of a Generator), DRR (in the case of a DRR) or ATRR (in the case of an ATRR) is responsible for identifying a Designated Entity (DE) or a Demand Designated Entity (DDE) for a given Asset, DRR or ATRR as applicable. However, a Lead MP is always ultimately responsible for all requirements and obligations assigned to a DE or DDE that is performing functions for that Lead MP. Each Lead MP shall 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

[1] Bulk Electric System (BES) is defined in the Glossary of Terms Used in NERC Reliability Standards.

be operated utilizing Good Utility Practice including making resources available for service as soon as possible after failures of equipment.

II. TECHNICAL REQUIREMENTS FOR GENERATORS

This section describes the basic technical requirements that a Generator shall meet to be considered for offer, dispatch and settlement. Generators shall also meet the eligibility requirements of Section III of the ISO New England Inc. Transmission, Markets and Services Tariff (ISO Tariff) and ISO New England Manuals (ISO Manuals) to offer into the New England Markets.

Criteria used to define registration options outlined in Section II.A.2 shall be used for all generating facilities on or after May 2, 2014. A registered SOG completed prior to May 2, 2014 remains as a SOG.

A. Generator Defined

1. A Generator shall be defined consistently for all ISO applications for the purposes of offer, dispatch and settlement. Defined Generators are represented in the ISO Energy Management System (EMS) and shall communicate with ISO through its approved DE registered in accordance with ISO New England Manual for Registration and Performance Auditing Manual M-RPA (M-RPA) having satisfied all requirements of a DE as defined in this OP in Section II.C - Designated Entity - Performance, Communication and Control.

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

2. The registration options for a generating facility and eligibility for each option depend on the size and interconnection of each generating facility.

    a. A generating facility (of any size) interconnected at 115 kV or above shall register as a Generator.

    b. A generating facility of five (5) MW or greater interconnected below 115 kV shall register as a Generator.

    c. A generating facility between one (1) MW and less than five (5) MW interconnected below 115 kV:

        - May register as a Generator

        - May register as a SOG or

- May elect to **not** register if **not** participating in any New England Markets other than as a load reducer

d. A generating facility less than one (1) MW interconnected below 115 kV:

- May register as a SOG or

- May elect to **not** register if **not** participating in any New England Markets other than as a load reducer

e. For the purpose of this OP, the aggregated maximum net output at or above 0 degrees F and interconnection voltage of a generating facility measured at the point at which the generating facility interconnects to the existing system are used to determine registration options.

f. For dispersed power generating facilities or distributed energy resources (excluding load reducers) that are interconnecting to the existing system through a common point of connection (e.g., a common collector or an express feeder), the following applies:

(1) For purposes of this OP, a common collector is a system, usually operating at distribution or sub-transmission voltage levels, designed primarily for interconnecting capacity to a common point of connection on an existing transmission or distribution element. Where the existing point of connection is a substation, the interconnection facilities are commonly referred to as an express feeder. An express feeder by definition serves **no** load other than that associated with the interconnected dispersed power generating facilities or distributed energy resource.

(2) Where multiple dispersed power generating facilities or distributed energy resources are connecting to the existing system through a common point of connection at the same time, all generating facilities/resources (excluding load reducers) interconnected at the common collector or express feeder system will be aggregated for the determination of the less than five (5) MW eligibility threshold. However, a new dispersed power generating facility or distributed energy resource seeking to interconnect at the same common collector or express feeder system as other dispersed power generating facilities or distributed energy resources will **not** be aggregated for the purposes of determining the less than five (5) MW eligibility threshold if both of the following conditions are met:

a) the other generating facilities or distributed energy resources on the common collector or express feeder system are existing, which, for purposes of this OP means, with executed interconnection agreements in place; and

b) the new dispersed power generating facility or distributed energy resource is **not** an Affiliate of the existing generating facilities or distributed energy resources on the common collector or express feeder system at the time of the interconnection request submittal

(3) The ISO may waive aggregation of an unaffiliated generating facility/resource that would otherwise be aggregated pursuant to Section II.A.2.f, if the ISO determines that **not** aggregating the unaffiliated generating facility/resource is acceptable from a reliability perspective.

(4) ISO shall consider project information included in the Generation Notification Form or Proposed Plan Application submitted pursuant to Section I.3.9 of the ISO Tariff to determine if multiple points of connection are present.

3. A Lead MP may combine generator units to form a defined Generator subject to Section II.C of this OP - Designated Entity - Performance, Communication and Control. Examples of a defined Generator, composed of multiple generator units, include: multi-unit hydro stations, solar farms, wind farms and most combined cycle units. A Lead MP's right to combine physical generator units to create a Generator for offer, dispatch and settlement is governed by the following rules:

   a. Generator units being combined shall 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.

   b. For a Generator that is a composite of multiple physical generator units, only the defined Generator will be represented, acted upon or allowed to transact in the various New England Markets.

   c. ISO shall determine if generator units located on different electrical buses may be combined and defined as a Generator.

   d. ISO shall consider if such a combination of generator 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.

4. Price offers shall only be submitted for a defined Generator.

5. ISO shall only perform settlement functions for defined Generators and SOGs.

6. To define a Generator, the Lead MP shall 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 Lead MP shall submit the technical data for each physical component of a unit regardless of it being modeled as a single unit or as multiple aggregations of the physical components of the unit, such as is

the case with some hydro units and combined cycle units. The Lead MP shall submit and maintain all requested data for the Generator. A defined Generator shall have an approved DE, provide all required data and have all required communications equipment in place and tested in accordance with ISO procedures prior to being available for dispatch. The Lead MP shall identify the DE. The Lead MP shall communicate to ISO through the identified DE for dispatch related matters. The data shall include, but may **not** be limited to, the following, as necessary:

- Generator Technical Data per Appendix A of this OP
- Form NX-12D, Generator Reactive Data (NX-12D), 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[2] per OP-16
- Form NX-9D, Static Capacitor/Reactor[3] per OP-16
- Short circuit data per OP-16
- Station one-line diagrams
- Dynamics models for Generators of 5 MW or greater compatible with Power System Simulator for Engineering (PSSe) including:
  - Generator, including wind turbines, photovoltaic systems, fuel cells and any other resource that delivers MW to the electric power system and meets the definition of a Generator in this OP
  - Excitation System
  - Governor
  - Power System Stabilizer (if equipped)
  - Models (both standard library models and user-written models) shall be consistent with the current version of the ISO New England Compliance Bulletin - MOD-032 - ISO New England Model Data Requirements and Reporting Procedures posted at:

    https://www.iso-ne.com/participate/rules-procedures/nerc-npcc

Generator dynamics models shall be provided to ISO prior to making changes to equipment that is part of a Generator . Changes to the above listed facilities shall be made in accordance with ISO Tariff Section I.3.9

[2] Form NX-9B, Transformer-FIXED/GSU/TCUL are terms used/defined in OP-16 Appendix B.
[3] Form NX-9D, Static Capacitor/Reactor are terms used/defined in OP-16 Appendix D.

and the Interconnection Procedures. Specified verification of generator dynamics models is also required in accordance with NERC Reliability Standards MOD-026, Verification of Models and Data for Generator Excitation Control System or Plant Volt/VAr Control Functions, and MOD-027, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions. Updates to existing models as well as proposed modeling changes shall be provided to ISO, as required by MOD-026 and MOD-027, using the Dynamics Data Management System (DDMS). Lead MPs shall initiate the data review by submitting the proposed MOD-026 and MOD-027 data changes in DDMS. All MOD-026 and MOD-027 data changes shall be submitted concurrently so that these changes can be reviewed simultaneously. Data submissions for MOD-026 and MOD-027shall include comparison curves of tests with model simulations and actual unit responses along with test reports. For further details refer to ISO Compliance Bulletin-MOD-026, MOD-027 & Tariff Provision of Validated Dynamics Models to ISO New England located at:

https://www.iso-ne.com/participate/rules-procedures/nerc-npcc

ISO shall initiate recertification of models for existing Generators annually in the first quarter of each calendar year in accordance with MOD-032 and this OP. Lead MPs for Generators shall indicate that the model represents the Generator as configured, including Automatic Voltage Regulator (AVR) and governor response, or that a change has been made. Recertification or information showing changes shall be provided to ISO within 45 calendar days of the initial ISO request. Responses to MOD-032 submittal requests shall be provided to ISO using DDMS. The ISO request for recertification shall include the modeling information currently maintained by ISO. Refer to ISO New England Compliance Bulletin - MOD-032 for additional information on Generator characteristics.

ISO may identify technical concerns with dynamic models and return the models to Lead MPs for review with a description of any technical concerns. Lead MPs shall review models and update the models as required to address any technical concerns. Lead MPs shall provide documented reviews addressing the technical concern with updates as required within 90 calendar days of receipt of the description of the technical concern or as specified by the associated NERC Reliability Standard. These requests and Lead MP responses shall be made using DDMS.

- Power Systems Computer-Aided Design (PSCAD) models for generators using power electronic equipment (e.g., wind generators, power inverter equipment). Models shall be provided to ISO by the method described with the request.

- DE registration per M-RPA

- Nuclear Generator Lead MPs shall provide proposed Nuclear Plant Interface Requirements (NPIRs) in accordance with Master/Local

Control Center Procedure No. 1 - Nuclear Plant Transmission Operations (M/LCC 1)

7. Equipment Requirements:

   a. Telemetry equipment as defined by ISO New England Operating Procedure No.18 - Metering and Telemetering Criteria (OP-18).

   b. A defined Generator shall be connected to only one (1) ISO Communications Front End (CFE) connected Remote Terminal Unit (RTU).

      (1) **No** RTU shall control more than five (5) dispatchable Generators without the review and approval of an exemption by ISO.

      (2) New exemptions are required for each additional Generator beyond five (5) as previously granted.

   c. For Generators that are participating in the Energy 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 are 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 Forward Reserve 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 Continental United States, 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 the DE.

   d. 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, the DE acting on behalf of the Lead MP shall 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 shall diligently pursue the repair and/or replacement of failed facilities on an expedited basis.

8. Whenever a Lead MP seeks to establish or change the DE responsible for managing dispatch for one or more of its Generator(s), the Lead MP and

DE are responsible for demonstrating to ISO that the proposed DE meets the technical requirements set forth in this OP prior to the ISO approving the proposed change(s) to become effective.

9. Generators shall provide and maintain up to date contact information to the applicable Local Control Center (LCC).

B. Telemetering and Revenue Metering

1. Telemetering for the Generator shall meet the requirements for speed and accuracy of OP-18. The Lead MP shall maintain and calibrate telemetering on an ongoing basis pursuant to OP-18.

2. Revenue metering shall meet the requirements of OP-18. Meter readings shall be forwarded to ISO for settlement, in a timely manner, as required by ISO Manuals and ISO New England Administrative Procedures (Administrative Procedures). The Lead MP shall maintain and calibrate revenue metering per the ISO requirements in OP-18.

3. Metering requirements and modeling options in the EMS and market systems for units less than five (5) MW will depend on their registration choice:

    a. Each Generator that is represented in the EMS and market systems shall meet the telemetering and revenue metering requirements described in II.B.1 and II.B.2 above.

    b. Each generating facility that registers as a SOG shall only meet the revenue metering requirements described in II.B.2 above; there are **no** telemetering requirements.

    c. Each generating facility that is **not** registered does **not** need telemetering.

C. Designated Entity - Performance, Communication and Control

1. Each DE shall provide dispatch services from a single physical location for a defined Generator and shall be the single point of contact to receive, acknowledge receipt, and implement ISO Dispatch Instructions and related communications. If prior approval from the ISO control room has been obtained, the operation from a single physical location allows for exigent conditions, as well as for infrequent, periodic testing & training needs.

    - **No** entity shall be recognized as a DE unless the entity meets the requirements in this OP and has been registered pursuant to ISO M-RPA.

    - All DE contact information shall be confirmed and/or updated by the DE on an annual basis or upon change.

2. Each DE shall comply with all requirements of the ISO Operating Documents to the same extent as if the Lead MP were carrying out the functions of the DE.

3. ISO shall communicate with the DE via electronic dispatch through an ISO connected RTU or voice communications through an automatic ringdown telephone circuit or one of the dedicated 24x7 phone numbers identified during DE registration in accordance with M-RPA.

4. The DE shall have the knowledge and authority to act on ISO Dispatch Instructions for all ISO registered assets it manages for dispatch, as defined in Section II.F of this OP - Dispatch Instructions.

    a. Any control equipment used to start, stop or vary the output of the Generator, from a remote location, shall meet the speed, accuracy and data channel requirements set in OP-18. Such equipment shall be maintained by the Lead 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[4] shall be notified as soon as practicable if the equipment is incapable of meeting the requirements of OP-18. Steps shall be taken to restore the equipment to normal operating conditions as soon as possible in accordance with OP-2.

    b. Each DE shall have a dedicated voice communication telephone (assigned public switched network land line phone number) for ISO dispatching purposes unless otherwise agreed to on a case-by-case basis by ISO.

5. In addition to the dedicated voice communication telephone, each DE is required to have a dedicated automatic ringdown telephone circuit to the ISO control room for any of the following unless ISO otherwise agrees on a case-by-case basis.

    - Each DE managed dispatchable Generator or aggregate of dispatchable generation greater than or equal to fifty (50) MW (net)

    - A Generator providing Regulation service

    - Other instances as determined on a case-by-case basis by ISO

    Further, certain Generators are critical to the BES under emergency conditions. These Generators are listed in Appendix D of this OP and shall install, maintain, operate, test and fund a voice communication 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 communications system shall be coordinated with, and

[4] System Operator is defined in the Glossary of Terms Used in NERC Reliability Standards.

acceptable to, the LCC for that Generator. Each LCC, in turn, is responsible for providing the requirements for the communications system and coordinating with each applicable Generator to effect the installation, operation and testing of the communications system.

6. Each DE for a Generator that participates in the New England Markets shall 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.

7. Each DE shall display to their DE Operator, the following parameters 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
   - Desired Dispatch Point (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

8. Acknowledgement and response to electronic dispatch via the human machine interface of the RTU shall also be performed at the same location as the voice communications unless otherwise agreed to on a case-by-case basis by ISO.

   a. Each DE shall maintain staff on duty to communicate with ISO System Operators at all times.

b. Each ISO CFE connected RTU shall be connected to only one DE. This verifies electronic dispatch can be acknowledged by a single, approved DE.

c. Each DE shall have equipment capable of reliably receiving and displaying to its operators the data in accordance with Section II.B. of this OP for each Generator it manages for dispatch

d. In instances where a Dispatch Instruction or any other order is issued verbally by an ISO System Operator, the verbal communication shall take precedence over all other forms of communication.

D. Designated Entity - Modifying DE Details

1. ISO shall evaluate all submitted DE change, registration or modification requests according to the required lead times with the requirements stated in this OP. ISO shall coordinate with each applicable Lead MP, transitioning DE, communication vendor, and any other authorized party in order to process requests.

2. A Lead MP shall provide at least thirty (30) calendar days' notice to change the DE, as defined in M-RPA.

    a. The effective date of the transfer is contingent on the proposed DE meeting the technical requirements and being registered and approved in accordance with M-RPA.

    b. Change requests concerning the DE communications infrastructure, moving the DE location, or changing the contact details shall only be submitted by a DE, as following:

        1) Changes to dedicated telephone numbers require at least thirty (30) calendar days' advance notice.

        2) Modifications to dedicated communications circuits (e.g., for automatic ringdown and/or RTU) require at least ninety (90) calendar days' advance notice.

        3) Contact details including person performing a role, their phone number and / or email address require at least seven (7) Business Days' advance notice.

    c. ISO approval of the change shall be contingent on the verification by ISO of the successful implementation and testing of the technical capabilities.

E. Emergency Message Indications

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

a. Each Generator shall have a specific message type indicator.

b. Each DE shall **not** employ visual messages that are common to multiple Generators.

c. Emergency messages shall have an audible alarm that is unique to emergency messages and **cannot** be disabled.

d. Emergency messages shall be “Message Type 2” (Emergency).

e. Messages that require acknowledgement shall have an “ACK Required = 1” on the RTU.

F. Dispatch Instructions

1. All Dispatch Instructions (Includes normal and emergency)

   a. If a DE is **not** capable of controlling the delivery of energy in accordance with its Offer Data, the DE shall 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

   a. Normal Dispatch Instructions shall be transmitted electronically to each DE every five minutes or less, depending on system conditions.

   b. Manual acknowledgement of a normal Dispatch Instruction is **not** required; however, compliance with the Dispatch Instruction shall be in accordance with Offer Data without delay.

   c. Fast Start Generators shall receive start-up and shutdown messages which shall be acknowledged by the DE within sixty (60) seconds. This acknowledgement requires physical action by staff at the DE. This item may be waived on a case-by-case basis by the ISO. Acknowledgement of a start-up or shutdown message shall indicate the DE intent to immediately comply with the Dispatch Instruction.

   d. Fast Start Generators shall **not** be shut down without receiving a shutdown message. A DDP below the Economic Minimum Limit that is **not** accompanied by a shutdown message is considered a dispatch to the Generator Economic Minimum Limit.

   e. 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

   a. 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.

b. Emergency Dispatch Instructions shall be transmitted electronically to each DE every five minutes or less, depending on system conditions.

c. Emergency messages shall be acknowledged by the DE within sixty (60) seconds of 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. Acknowledgement of the emergency message shall indicate the DE intent to immediately comply with the Dispatch Instruction.

d. Emergency Dispatch Instructions shall be followed in accordance with Offer Data without delay.

e. 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 shall take action to comply with the Dispatch Instructions in accordance with their Offer Data.

f. Fast Start Generators shall **not** be shut down without receiving a shutdown message. A DDP below the Economic Minimum Limit that is **not** accompanied by a shutdown message is considered a dispatch to the Generator Economic Minimum Limit.

g. 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 shall **not** be placed on Regulation unless called for by ISO System Operators.

h. While the emergency message is active, voice communication to the ISO control room related to the Dispatch Instructions should be limited to only those pertaining to clarifying the Dispatch Instructions.

G. Operational Considerations

1. A Generator shall be dispatched as directed by ISO in accordance with ISO New England Operating Procedure No. 1 - Central Dispatch Operating Responsibilities and Authority (OP-1), and the operating characteristics submitted by the Lead MP. The safety of operating personnel and prevention of damage to equipment are the sole responsibility of the Lead MP, and shall be the priority at all times.

2. Each Generator that is treated as a SOG may have additional responsibility under ISO New England Operating Procedure No. 4 - Action During a Capacity Deficiency (OP-4).

3. Both the Planned Outages and Maintenance Outages[5] of the Generator shall be done in accordance with ISO generator maintenance scheduling

[5] Planned Outage and Maintenance Outage are defined in OP-5.

procedures per ISO New England Operating Procedure No. 5 - Resource Maintenance and Outage Scheduling. (OP-5)

4. The Lead MP shall, at all times, comply with all applicable switching and tagging procedures in effect by the authorities governing switching and tagging operations in the field.

H. Voltage Control

1. The MVAr production of a Generator is an important factor in the reliable operation of the New England RCA/BAA. Each Lead MP shall 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 is specified for both On-Peak and Off-Peak[6] load periods as contained in OP-12, Appendix B, or as otherwise specified by ISO or an LCC. ISO and the LCC shall have the authority to direct the Lead MP to deviate from the normal voltage schedule to address operating situations. Each Generator shall participate, to the limit of their capability as documented in its NX-12D and as summarized in OP-12, Appendix B, and 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 Lead MP shall keep and maintain an automatic voltage regulator (AVR) in service and regulating to the voltage schedule on all generating units comprising a Generator unless granted an exemption under the provisions in Section 5 of Master/Local Control Center Procedure No. 8 - Coordination of Generator Voltage Regulator and Power System Stabilizer Outages (M/LCC 8). Generators that have applied for and received an exemption shall be listed in M/LCC 8, Attachment A - Generators Exempted From AVR Requirements.

3. Each Lead MP (except those for whom an exemption has been granted, as described in Section II.H.2) shall maintain the AVR in good operating condition.

4. Each Lead MP shall provide to ISO on ISO Form NX-12D - Generator Reactive Data Form, in accordance with Appendix B of this OP, information describing the periods of time when conditions occur (if any) where the Lead MP routinely expects that its Generator will **not** operate with the AVR in service and controlling voltage (such as during start-up or shutdown).

5. Actual or expected changes in AVR Operating status shall be reported in Real-Time in accordance with OP-12 and M/LCC 8, unless the requirement for such Real-Time reporting of AVR operating status is automatically waived during the periods of time when Real-Time conditions occur that are as described by the Lead MP on the Form NX-12D pertaining to when the Lead MP routinely expects that its Generator

[6] On-Peak and Off-Peak are defined in the Glossary of Terms Used in NERC Reliability Standards.

will **not** operate with the AVR in service and controlling voltage (such as during start-up or shutdown). When such conditions occur that match the conditions described on Form NX-12D, this serves as advance standing notification and Real-Time reporting is **not** required.

I. Governor Control

1. Where **not** already required to do so pursuant to the Interconnection Agreement, each Lead MP shall provide, maintain and operate a "functioning governor" on each Generator with a capability of ten (10) MW or greater. For the purposes of this OP, a "functioning governor" includes hardware or software that provides autonomous frequency-responsive power control. This requirement applies to all conventional Generators and non-conventional power sources including but **not** limited to: defined Generator Assets, aggregated Generator Assets, wind turbine Generator Assets, all elements of a photovoltaic Generator Asset, etc. The equipment providing "governor functionality" shall be set such that:

    a. It has a speed droop based on nameplate capability or the value determined in Section II.A.2 of this OP set between a minimum of four percent (4%) and a maximum of five percent (5%);

    b. It has a frequency response deadband of **no** greater than 59.964-60.036 Hz; and

    c. The real power response is **not** inhibited by effects of outer loop controls (such as operator setpoint controls and load control but excluding AGC) that would override the governor response (including blocked or nonfunctioning governors or modes of operating that limit Frequency Response[7]). Meeting this requirement results in providing primary frequency response.

2. Upon ISO request, the Lead MP shall verify that actual governor operation in response to load control and/or active power/frequency control approximates the specified droop. Verification shall be in the form of Plant Information (PI) data indicating MW response to frequency events during a fifteen (15) minute interval (MW and Hz timestamp data five (5) minutes prior and ten (10) minutes post an identified frequency event).

3. The DE, acting on behalf of the Lead MP, shall inform ISO of actual or expected changes in governor operating status per Master/Local Control Center Procedure No. 10 - Generator Governor Control and Operation (M/LCC 10). Each Lead MP is responsible for periodic testing and maintenance of the Generator governor.

4. Except as otherwise provided in the Interconnection Agreement, ISO shall consider a well-documented and technically valid request to be exempt from the requirements of this Section II.I. All requests shall be submitted through "Ask ISO" and shall include "Governor Exemption Request" with

[7] Frequency Response is defined in the Glossary of Terms Used in NERC Reliability Standards.

the Asset name and ID number in the issue summary. Any such request shall be reviewed by ISO technical staff for acceptability. Any Generator whose exemption is accepted shall be listed on a governor exemption list in M/LCC 10 Attachment A - Generators Exempted from Governor Requirements. A Generator listed in M/LCC 10 Attachment A either does **not** have a governor or does **not** operate its governor in conformance with the requirements in this OP. For all such Generators, ISO has reviewed the impact of this status and has determined that this status is acceptable from a reliability perspective. If evaluation is needed ISO will undertake evaluation under ISO Tariff Section I.3.9. All governor exemption requests shall be reported to the Reliability Committee. If accepted by ISO, the Generator Asset and unit, if applicable, will be listed in M/LCC 10 Attachment A. The exemption process shall only consider a full exemption from all governor requirements.

Addition to the exemption list does **not** preclude reevaluation required with changes processed through the Large Generator Interconnection Procedure (LGIP) / Small Generator Interconnection Procedure (SGIP) Schedules 22 and 23, respectively. These exemption criteria do **not** relieve that resource from adhering to any other ISO New England Operating Documents or program requirements.

J. Interconnection

1. A Generator seeking to connect its facilities to transmission facilities shall have a valid Interconnection Agreement(s) in place with the Transmission Owners(s) with which the Generator is seeking 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.

K. System Protection

1. At a minimum, each Lead MP shall 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 Lead MP shall maintain and upgrade 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 shall **not** occur while the unit is on-line. All requests for such maintenance shall 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. NERC Reliability Standard PRC-006-NPCC-01 identifies thresholds for setting underfrequency trip protection for generators. The Lead MP for a

Generator shall verify that its Generator meets the appropriate figure in PRC-006-NPCC-01 for underfrequency tripping unless it has arranged compensatory load shedding with a Distribution Provider or Transmission Owner in the same underfrequency island and in accordance with the standard.[8]

L. Power System Stabilizers

1. Where power system stabilizer (PSS) equipment is installed on a Generator for the purpose of maintaining system stability, the Lead MP shall maintain the PSS equipment in good operating condition, and promptly report to ISO any problems interfering with PSS proper operation. The Lead MP shall 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 - Generators Requiring PSS Devices In/Out of Service. Each Lead MP shall 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.

M. Blackstart Capability

1. Each Lead MP for a Generator that provides blackstart capability from one of their Generators and that Generator has been incorporated in the ISO system restoration plan and/or as defined by ISO New England Operating Procedure No. 11 - Blackstart Resource Administration (OP-11) must maintain that Generator in good operating condition. Each Lead MP shall promptly report to ISO, or the appropriate dispatch center, any problems interfering with the blackstart capability of each such Designated Blackstart Resource (DBR) Generator.

N. Additional Requirements for Wind Powered Generators

1. Due to the unique nature and operating parameters associated with wind powered generation, additional specific requirements for these resources are necessary. Wind plants modeled and defined in the ISO EMS shall telemeter additional reliability data. Appendix F - Wind Plant Operator Guide details the criteria and requirements for wind powered Generators and shall be used by MPs for interconnected operation. The requirements shall be in effect and become enforceable upon installation of the communications equipment necessary to perform the data transfer.

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[8] Requirement R 13 of PRC-006-NPCC-01 provides that "[e]ach Generator Owner shall set each generator underfrequency trip relay, if so equipped, *below* the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19." (Emphasis added). In a September 22, 2015 presentation, NPCC provided a compliance clarification under which setting underfrequency trip relays *"on or below the curve"* is acceptable to show compliance with Requirement R 13 of PRC-006-NPCC-01.

III. TECHNICAL REQUIREMENTS FOR ALTERNATIVE TECHNOLOGY REGULATION RESOURCES

This section describes the basic technical requirements that shall be met by each Alternative Technology Regulation Resource (ATRR) to be considered in the Regulation Market offer process. However, each ATRR shall meet other eligibility requirements of Section III of the ISO Tariff and ISO Manuals to offer into the New England Markets.

A. ATRR Defined

1. Each ATRR shall be defined consistently for all ISO applications. That is, it shall be defined in the same manner for the purposes of Regulation offers, dispatch and settlement. Each ATRR shall communicate with ISO through its approved DE registered in accordance with ISO M-RPA having satisfied all requirements of a DE as defined in this OP in Section III.C - Designated Entity - Performance, Communication and Control. Registration of an ATRR will be subject to the provisions of ISO Tariff Section I.3.9, to the extent that the operation of the proposed ATRR may have a significant effect on the stability, reliability or operating characteristics of the New England RCA/BAA. A defined ATRR can only be dispatched via electronic dispatch for Regulation service.

    a. A defined ATRR shall be subject to the below Section III.C - Designated Entity - Performance, Communication and Control.

2. The Lead MP right to aggregate sub-resources to define an ATRR for offer, dispatch and settlement shall be governed by the following rules:

    a. Individual sub-resources shall be less than one (1) MW of Regulation Capacity. If greater than or equal to one (1) MW of Regulation Capacity, it shall register as a separate ATRR.

    b. ISO shall determine if sub-resources may be combined and defined as one ATRR.

    c. ISO shall consider if such a combination of sub-resources interferes with effective control and/or system reliability.

3. To define an ATRR, the Lead MP shall submit any technical data with respect to an ATRR and any sub-resources when ISO determines it is necessary for ISO to carry out its responsibility of reliable and efficient operation of the BES. The Lead MP shall submit the technical data for each sub-resource irrespective of it being a single unit or an aggregation. The Lead MP shall submit and maintain all requested data of the ATRR. A defined ATRR shall have an approved DE, provide all required data and have all required communications equipment in place and tested in accordance with ISO procedures prior to being available for dispatch. The Lead MP shall identify the DE. The Lead MP shall communicate to ISO

through the identified DE. The data may include, but **not** be limited to, the following, as necessary:

a. ATRR Technical Data per Appendix G of this OP

b. Textual description of the technical and operational characteristics of each sub-resource

c. One-line diagrams

d. Registration per M-RPA (includes DE registration, as necessary)

4. Equipment Requirements:

a. Telemetering as defined by OP-18

b. A defined ATRR shall be connected to only one (1) ISO CFE connected RTU. **No** RTU shall control more than five (5) ATRRs without the review and approval of an exemption by ISO.

c. A new exemption is required for each additional ATRR beyond five (5) as previously granted.

d. Communications equipment, hardware and software shall be 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 Regulation 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 Continental United States, to provide for the electronic transmission of data relative to the dispatch to carry out the Real-Time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in injection or consumption of ATRR(s). An ATRR is considered to have EDC when it is capable of receiving, responding to, and changing output in response to electronic Dispatch Instructions issued to the ISO CFE connected RTU of its DE.

5. To define a new ATRR, a minimum of one hundred and twenty (120) calendar days' advance notice to ISO is required.

To change data for an existing ATRR definition:,

- A minimum of seven (7) calendar days' advance notice to ISO is required. The advance notice period commences upon ISO receipt of the criteria detailed in Section III.A.3 of this OP.

- Dispatch methodology may be changed to be effective at the start of every calendar quarter. Requests to change the dispatch method of an ATRR shall be received **no** later than thirty (30) Business Days before the requested effective date of the change. There are three (3) dispatch methodology selections
    - Continuous - energy neutral
    - Trinary - energy neutral
    - Continuous - non-energy neutral

6. Whenever a Lead MP wishes to establish or change the DE responsible for managing dispatch for its ATRR(s), the Lead MP and DE shall demonstrate to ISO that the proposed DE meets the technical requirements set forth in this OP prior to ISO approving the proposed change to become effective.

B. Telemetering and Revenue Metering

1. Telemetering shall be maintained and calibrated by the Lead MP or their designee on an ongoing basis per OP-18. ISO does **not** specify how the DE shall communicate with or obtain telemetering data from the sub-resource(s). However, the telemetering requirement for the ATRR to provide data to ISO shall meet the speed and accuracy requirements of OP-18. Metering requirements for ATRRs and any/all sub-resource(s) less than five (5) MW shall depend on their modeling option in the EMS and market systems:
    a. Each ATRR, either as single or aggregate, greater than five (5) MW at a single node is represented in the EMS and shall meet the telemetering requirements described in III.B.1 above

C. Designated Entity - Performance, Communication and Control

1. Each DE shall provide dispatch services from a single physical location for a defined ATRR and shall be the single point of contact to receive, acknowledge receipt, and implement ISO Dispatch Instructions and related communications. If prior approval from the ISO control room has been obtained, the operation from a single physical location shall allow for exigent conditions, as well as for infrequent, periodic testing & training needs.

- **No** entity shall be recognized as a DE unless it meets the requirements in this OP and has been registered pursuant to ISO M-RPA.
- All DE contact information shall be confirmed and/or updated by the DE on an annual basis or upon change.

2. Each DE shall comply with all requirements of the ISO Operating Documents to the same extent as if the Lead MP were carrying out the functions of the DE.

3. ISO shall communicate with the DE via electronic dispatch through an ISO connected RTU or voice communications through an automatic ringdown telephone circuit or one of the dedicated 24x7 phone numbers identified during DE registration in accordance with M-RPA.

4. The DE shall have the knowledge and authority to act on ISO Dispatch Instructions for all ISO registered assets it manages for dispatch, as defined in Section III.E AGC Dispatch Instructions of this OP.

    a. Any control equipment used to start, stop or vary the output of the ATRR, from a remote location, shall meet the speed, accuracy and data channel requirements of OP-18. Such equipment shall be maintained by the Lead MP according to ISO requirements contained in OP-18 and OP-2. ISO System Operators shall be notified as soon as practicable if the equipment is incapable of meeting the requirements of OP-18. Steps shall be taken to restore the equipment to normal operating conditions as soon as possible pursuant to OP-2.

    b. Each DE shall have a dedicated voice communication telephone (assigned public switched network land line phone number) for ISO dispatching purposes unless ISO otherwise agrees on a case-by-case basis.

5. In addition to the dedicated voice communication telephone, each DE is required to have a dedicated automatic ringdown telephone circuit to the ISO control room for any of the following unless ISO otherwise agrees on a case-by-case basis.

    - Each DE managed ATRR or aggregate of ATRRs greater than or equal to fifty (50) MW capacity (net)
    - Other instances that ISO determines on a case-by-case basis

6. Each DE for an ATRR shall 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.

7. Each DE shall display to their DE operator, the following parameters for each ATRR, as defined in Section III.A.4 of this OP, in New England that is under their responsibility.

    a. AGC Setpoint

    b. Actual Injection / Consumption

c. Response Rate

d. Regulation High Limit

e. Regulation Low Limit

f. ATRR Availability

g. On Regulation Status

h. Heartbeat

ATRR parameter display shall be at the same location as the voice communications unless ISO otherwise agrees on a case-by-case basis.

8. Each DE shall maintain staff on duty to communicate with ISO System Operators at all times.

9. Each ISO CFE connected RTU shall be connected to only one DE. This verifies electronic Dispatch Instruction can to be acknowledged by a single, approved DE.

10. Each DE shall have equipment capable of reliably receiving and displaying to its operators the data in accordance with Section III.B. - Telemetering And Revenue Metering for each ATRR it manages for dispatch.

11. Dispatch Instructions or any other operating instructions issued verbally by ISO System Operators shall take precedence over all other forms of communication.

D. Designated Entity - Modifying DE Details

1. ISO shall evaluate each submitted DE change, registration or modification request according to the required lead times with the requirements stated in this OP. ISO shall coordinate with each applicable Lead MP, transitioning DE, communication vendor, and any other authorized party in order to process the request.

2. A Lead MP shall provide at least thirty (30) calendar days' notice to change the DE, as defined in M-RPA.

   a. The effective date of the transfer is contingent on the proposed DE meeting the technical requirements and being registered and approved in accordance with M-RPA.

   b. Change requests concerning the DE communications infrastructure, moving the DE location, or changing the contact details can only be submitted by a DE, in accordance with the following:

      - Changes to dedicated telephone numbers require at least thirty (30) calendar days' advance notice.

- Modifications to dedicated communications circuits (e.g., for automatic ringdown and/or RTU) require at least ninety (90) calendar days' advance notice.
- Contact details including person performing a role, their phone number and / or email address require at least seven (7) Business Days' advance notice.

c. ISO approval of the change is contingent on the verification by ISO of the successful implementation and testing of the technical capabilities.

E. AGC Dispatch Instructions

1. All AGC Dispatch Instructions (Includes normal and emergency)

   a. If a DE is **not** capable of controlling the delivery of Regulation service in accordance with its Regulation Offer Data, the DE shall notify the ISO System Operators as soon as practicable. Efforts shall be made to forecast ATRR capabilities and submit those parameters appropriately.

2. Normal AGC Dispatch

   a. Normal AGC setpoints are transmitted electronically to each DE every four seconds or less.

3. Emergency Dispatch Instructions

   a. Emergency messages will be issued by the ISO System Operators when an emergency issue requires an immediate response by ATRRs outside of the normal dispatch protocol.

   b. 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. An ATRR shall be dispatched as directed by ISO in accordance with OP-1, and the operating characteristics submitted by the Lead MP. The safety of operating personnel and prevention of damage to equipment are the sole responsibility of the Lead MP, and shall be the priority at all times.

2. Both Planned Outages and Maintenance Outages of the ATRR shall be performed in accordance with ISO Generator maintenance scheduling procedures per ISO New England Operating Procedure No. 5 - Resources Maintenance and Outage Scheduling (OP-5).

3. The Lead MP shall, 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. An ATRR shall **not** adversely impact the voltage control performance at the point of Interconnection.

H. Interconnection

1. An ATRR shall follow the interconnection requirements for the type(s) of facility(ies) that will be participating as part of the ATRR. 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.

I. System Protection

1. Operation as an ATRR, either by an individual facility or aggregate of sub-resources, shall have system protection appropriate to the classification of that facility or sub-resource for each interconnection.

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

This section describes the basic technical requirements that shall be met by each DARD in order for it to be considered in the bidding process. However, each DARD shall meet other eligibility requirements of Section III of the ISO Tariff and ISO Manuals to bid into the New England Markets.

A. DARDs

1. Each DARD shall be defined consistently for all ISO applications. That is, it shall be defined in the same manner for the purposes of bidding, dispatch and settlement. Each DARD shall communicate with ISO through its approved DE registered in accordance with M-RPA having satisfied all requirements for a DE as defined in Section IV.C of this OP - Designated Entity - Performance, Communication and Control.

2. A bid shall only be submitted for a defined DARD. Bid parameters for a DARD shall be submitted by the Lead MP.

3. ISO shall only perform settlement functions for a defined DARD.

4. Each DARD shall be 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 Lead MP shall 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 Lead MP shall submit and maintain all requested data. The Lead MP shall identify the DE. The Lead MP shall communicate to ISO through the identified DE for dispatch related matters. The technical data shall include, but is **not** limited to, the following:

    a. Dispatchable Asset Related Demand Technical Data, per Appendix E of this OP

    b. NX-9 data as applicable, per OP-16

    c. Form NX-9B as applicable, Transformer-FIXED/GSU/TCUL, including each physical component, per OP-16

    d. Form NX-9D as applicable, Static Capacitor/Reactor, including each physical component, per OP-16

    e. DE registration per M-RPA

6. Equipment Requirements:

    a. Telemetering as defined by OP-18

b. Each DARD shall have 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.

c. 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 Continental United States, 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 is 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 Energy Market and Reserve Market is conditioned upon having EDC installed.

d. 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 each DARD 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 any failed equipment on an expedited basis.

e. 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 are required by ISO Manuals and Administrative Procedures. ISO may issue Dispatch Instructions as frequently as needed.

f. A DARD shall be connected to only one (1) ISO CFE connected RTU. **No** RTU shall control more than five (5) DARDS without the review and approval of an exemption by the ISO.

g. New exemptions are required for each additional DARD beyond five (5) as previously granted.

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

a. To define a new DARD, a minimum of one hundred and twenty (120) calendar days' advance notice is required. The one hundred and twenty (120) calendar day period commences upon ISO receipt of the criteria detailed in Section IV.A.5 of this OP.

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

8. Whenever a Lead MP seeks to establish or change the DE responsible for managing dispatch for its DARD(s), the Lead MP and DE shall demonstrate to ISO that the proposed DE meets the technical requirements set forth in this OP prior to the ISO approving the proposed change to become effective.

B. Telemetering and Revenue Metering

1. Telemetering from each DARD shall meet the requirements for speed and accuracy of OP-18. The Lead MP shall telemeter the instantaneous MW value of the DARD. Telemetering shall be maintained and calibrated by the Lead MP on an ongoing basis per OP-18.

2. Revenue metering shall meet ISO accuracy requirements of OP-18 for all DARDs. Revenue metering readings shall be forwarded to ISO for settlement in a timely manner as required by ISO Manuals and Administrative Procedures. The Lead MP is responsible for maintenance and calibration of revenue metering pursuant to OP-18.

C. Designated Entity - Performance, Communication and Control

Each DE shall provide dispatch services from a single physical location for a DARD and shall be the single point of contact to receive, acknowledge receipt, and implement ISO Dispatch Instructions and related communications. If prior approval from the ISO control room has been obtained, the operation from a single physical location allows for exigent conditions, as well as for infrequent, periodic testing and training.

a. **No** entity shall be recognized as a DE unless that DE meets the requirements in this OP and has been registered pursuant to M-RPA.

b. All DE contact information shall be confirmed and/or updated by the DE on an annual basis or upon change.

Each DE shall comply with all requirements of the ISO Operating Documents to the same extent as if the Lead MP were carrying out the functions of the DE.

ISO shall communicate with the DE via electronic dispatch through an ISO connected RTU or voice communications through an automatic ringdown circuit or one of the dedicated 24x7 phone numbers identified during DE registration in accordance with M-RPA.

The DE shall have the knowledge and authority to act on ISO Dispatch Instructions for all ISO registered assets it manages for dispatch, as defined in Section IV.F of this OP - Dispatch Instructions.

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

2. The DE of each DARD shall have a dedicated voice communication telephone (assigned public switched network land line phone number) for ISO dispatching purposes unless otherwise agreed to on a case-by-case basis by ISO.

In addition to the dedicated voice communication telephone, each DE is required to have a dedicated automatic ringdown telephone circuit to the ISO control room for any of the following unless otherwise agreed to on a case-by-case basis by ISO.

    a. DE managed dispatchable DARD(s) singly or in aggregate greater than or equal to 50 MW (net).

    b. Other instances as determined on a case-by-case basis by the ISO.

3. Certain DARDs are critical to the BES 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 shall be coordinated with, and acceptable to, the DARD LCC. Each LCC shall, in turn, provide the requirements for the communications system and coordinate with the DARD owner to effect the installation, maintenance, operation and testing of the communication systems.

Each DE for a DARD that participates in the New England Markets shall 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 shall 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 shall display to their DE Operators the following parameters for each DARD that is dispatchable, as defined in Section IV.A.6 of this OP, in New England and is under their responsibility:

    a. ACK Required (i.e. Acknowledgement Required)

b. Message Type

(1) Normal

(2) Emergency

(3) Start Up

(4) Shut Down

c. DDP

d. Actual Consumption

e. Minimum Consumption Limit

f. Maximum Consumption Limit

g. Response Rate

h. Unit Control Mode

i. Heartbeat

Acknowledgement and response to electronic dispatch via the human machine interface of the RTU shall also be performed at the same location as the voice communications unless otherwise agreed to on a case-by-case basis by ISO.

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

6. Each ISO CFE connected RTU shall be connected to only one DE. This verifies electronic Dispatch Instruction can be acknowledged by a single, ISO-approved DE.

7. Each DE shall have equipment capable of reliably receiving and displaying to its operators the data in accordance with Section IV.B of this OP - Telemetering And Revenue Metering for each DARD it manages for dispatch.

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

D. Designated Entity - Modifying DE Details

1. ISO shall evaluate all submitted DE change, registration or modification requests according to the required lead times with the requirements stated in this OP. ISO shall coordinate with Lead MPs, transitioning DEs, communication vendors, and any other authorized parties in order to process requests.

2. A Lead MP shall provide at least thirty (30) calendar days' notice to change the DE, as defined in M-RPA.

    a. The effective date of the transfer is contingent on the proposed DE meeting the technical requirements and being registered and approved in accordance with M-RPA.

3. Change requests concerning the DE communications infrastructure, moving the DE location, or changing the contact details shall be submitted by a DE, in accordance with the following:

    a. Changes to dedicated telephone numbers require at least thirty (30) calendar days' advance notice.

    b. Modifications to dedicated communications circuits (e.g., automatic ringdown and/or RTU) require at least ninety (90) calendar days' advance notice.

    c. Contact details including person performing a role, their phone number and / or email address require at least seven (7) Business Days' advance notice.

Approval of the change by ISO shall be contingent on the verification by ISO of the successful implementation and testing of the technical capabilities.

E. Emergency Message Indications

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

    a. Each DARD shall have a specific Message Type indicator.

    b. Each DE shall **not** employ visual messages that are common to multiple assets.

    c. Emergency messages shall have an audible alarm that is unique to emergency messages and **cannot** be disabled.

    d. Emergency messages are Message Type 2 (Emergency).

    e. Messages that require acknowledgement have an ACK Required = 1 on the RTU.

F. Dispatch Instructions

1. All Dispatch Instructions (Includes normal and emergency)

    a. If a DE is **not** capable of controlling the consumption of energy in accordance with its Offer Data, the DE shall 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

    a. Normal Dispatch Instructions are transmitted electronically to each DE every five minutes or less, depending on system conditions.

    b. 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.

    c. 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

    a. 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.

    b. Emergency Dispatch Instructions are transmitted electronically to each DE every five minutes or less, depending on system conditions.

    c. Emergency messages shall be acknowledged by the DE within sixty (60) seconds of the receipt of the message. This item may be waived on a case-by-case basis by ISO. This acknowledgement requires physical action by staff at the DE. Acknowledgement of the emergency message shall indicate the DE intent to immediately comply with Dispatch Instruction.

    d. 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.

    e. In an emergency, DARDs will receive an emergency message in lieu of a shutdown message. The DDP that accompanies the emergency message dictates the desired response from the DARD. The DE shall take action to comply with the Dispatch Instructions.

    f. 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.

G. Operational Considerations

1. Each DARD shall be dispatched as directed by ISO in accordance with OP-1, and the operating characteristics submitted by the Lead MP. The safety of operating personnel and prevention of damage to equipment are the sole responsibility of the Lead MP, and shall be the priority at all times.

2. The Lead MP shall maintain the DARD control equipment in good operating condition, and shall promptly report to ISO any problems interfering with its proper operation.

3. Both Planned Outages and Maintenance Outages of DARDs shall be done in accordance with the ISO resource maintenance and outage scheduling procedures of OP-5.

4. At all times the Lead MP shall comply with all applicable switching and tagging procedures in effect by the authorities governing switching and tagging operations in the field.

H. Interconnection

1. Each DARD seeking to connect its facility to transmission facilities shall have a valid Interconnection or Service Agreement(s) in place with the Transmission Owners(s) with which the DARD is seeking 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. TECHNICAL REQUIREMENTS FOR ASSET RELATED DEMANDS (ARDS) (NOT DISPATCHABLE)

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

A. ARDs (Not Dispatchable)

1. Each ARD shall be defined consistently for all ISO applications. That is, it shall be defined in the same manner for the purposes of bidding and settlement.

2. ISO shall only perform settlement functions for a defined ARD.

3. To define an ARD, the Lead MP shall 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 shall be subject to the provisions of ISO Tariff Section I.3.9 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 Lead MP shall submit and maintain all requested data. The Lead MP shall identify the DE. The Lead MP shall communicate to ISO through the identified DE for dispatch related matters. The data includes, but is **not** limited to, the following:

   a. Asset Related Demand Technical Data, per Appendix E of this OP

   c. NX-9 data as applicable, per OP-16, Transmission System Data

   c. Form NX-9B as applicable, Transformer-FIXED/GSU/TCUL, including each physical component, per OP-16

   d. Form NX-9D as applicable, Static Capacitor/Reactor, including each physical component, per OP-16

4. Equipment Requirements:

   a. Telemetering as defined by OP-18

5. ARD definitions shall be submitted to ISO in accordance with the following advance notice requirements:

   a. To define a new ARD, a minimum of one hundred and twenty (120) calendar days' advance notice is required. The one hundred and twenty (120) calendar day period commences upon ISO receipt of the criteria detailed in Section V.A.3 of this OP.

   b. The ISO Manuals should be referenced to change the capability of an existing ARD.

B. Telemetering and Revenue Metering

1. Telemetering from each ARD shall meet the requirements for speed and accuracy per OP-18. The Lead MP shall telemeter the instantaneous MW value of an ARD. Telemetering must be maintained and calibrated by the Lead MP on an ongoing basis per OP-18.

2. Revenue metering shall meet the requirements of OP-18 for each ARD. Meter readings shall be forwarded to ISO for settlement in a timely manner as required per ISO Manuals and Administrative Procedures. The Lead MP shall maintain and calibrate the revenue metering per ISO requirements as contained in OP-18.

C. Interconnection

1. An ARD seeking to connect its facility to transmission facilities shall 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.

VI. TECHNICAL REQUIREMENTS FOR DEMAND RESPONSE RESOURCES (DRRs)

This section describes the basic technical requirements that must be met by each DRR in order for it to be considered for offer, dispatch and settlement. DRRs must also meet the eligibility requirements of Section III of the ISO Tariff and ISO Manuals in order to offer into the New England Markets.

DRRs shall comply with the requirements outlined in this Section VI by June 1, 2018 unless agreed to by ISO on a case-by-case basis based on a demonstration that there is good cause to allow for a delay in compliance for a specific period.

A. DRR Defined

1. Each DRR shall be defined consistently for all ISO applications. That is, it shall be defined in the same manner for the purposes of offers, dispatch and settlements. Each DRR shall communicate with ISO through its approved DDE registered in accordance with M-RPA having satisfied all requirements of a DDE as defined in Section VI.C - DDE - Performance, Communication and Control of this OP.

    a. To define a DRR, the Lead MP shall submit any technical data with respect to a DRR that ISO determines to be necessary for ISO to carry out its responsibility to reliably and efficiently operate the power system. Each Lead MP shall submit and maintain all requested data. The Lead MP shall identify the DDE. The Lead MP shall communicate to ISO through the identified DDE for dispatch-related matters. The technical data shall include, but is **not** limited to, registration through the ISO Customer Asset Management System (CAMS) application which is accessible at https://smd.iso-ne.com .

2. A Lead MP may submit a demand reduction offer only for a defined DRR. Bid parameters for a DRR shall be submitted by the Lead MP.

3. ISO shall perform settlement functions only for defined DRRs.

4. Each DRR is eligible to provide Operating Reserve in accordance with OP-8.

5. A DRR definition shall be submitted to ISO in accordance with the following advance notice requirements:

    a. A minimum of seven (7) calendar days' advance notice is required, prior to the monthly model cut, to modify assets associated with a DRR or modify its definition in accordance with M-RPA.

    b. The seven (7) calendar day period commences upon ISO approval of the criteria detailed in M-RPA.

6. Equipment Requirements:

a. Telemetry equipment as defined in OP-18.

(1) A defined DRR shall be connected to only one (1) ISO CFE connected RTU.

b. For DRRs that are participating in the New England Markets and/or are dispatchable in Real-Time, communications equipment, hardware and software sufficient to enable the DDE to receive, acknowledge receipt, and implement 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 DDE for verbal Dispatch Instructions shall **not** exceed the number of ISO CFE connected RTUs installed for receipt of electronic Dispatch Instructions without prior approval from ISO. Participation in the Energy Market and Forward Reserve 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 Continental United States, to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of a DRR to carry out the Real-Time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of a DRR. A DRR is considered to have EDC when it is capable of receiving, responding to, and changing output in response to electronic Dispatch Instructions issued to the ISO CFE connected RTU of its DDE.

c. In the event of failure of the ISO CFE connected RTU or the failure of communications or other equipment between the ISO CFE connected RTU and the DRR connected to the ISO CFE connected RTU, the DDE acting on behalf of the Lead MP shall convey the Dispatch Instructions issued by ISO to the DRR(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 equipment on an expedited basis.

B. Telemetering and Revenue Metering

1. Telemetering for each Demand Response Asset (DRA) associated with a DRR shall meet the speed and accuracy requirements of OP-18. Telemetering shall be maintained and calibrated by the Lead MP on an ongoing basis pursuant to OP-18.

2. Revenue metering shall meet speed and accuracy requirements of OP-18 for each DRA associated with a DRR. Revenue meter readings shall be submitted via the DRR telemetering to ISO in near Real-Time. The Lead MP (or designee) shall perform maintenance and calibration of revenue metering pursuant to OP-18.

C. DDE - Performance, Communication and Control

1. Each DDE shall provide dispatch services from a single physical location for their DRRs and shall be the single point of contact to receive, acknowledge receipt, and implement Dispatch Instructions and related communications. If prior approval from the ISO control room has been obtained, the operation from a single physical location allows for exigent conditions, as well as for infrequent, periodic testing and training.

    a. **No** entity shall be recognized as a DDE unless the entity meets the requirements of this OP and has been registered pursuant to M-RPA.

    b. All DDE contact information shall be confirmed and/or updated by the DDE on an annual basis or upon change.

    c. Whenever a Lead MP seeks to establish or change the DDE responsible for managing dispatch for its DRR(s), the Lead MP and DDE shall demonstrate to ISO that the proposed DDE meets the technical requirements set forth in this OP prior to ISO approving the proposed DDE establishment or change to become effective.

2. Each DDE shall comply with all requirements of the ISO Operating Documents to the same extent as if the Lead MP were carrying out the functions of the DDE.

3. ISO shall communicate with the DDE via electronic dispatch through an ISO connected RTU or voice communications through an automatic ringdown circuit or one of the dedicated 24x7 phone numbers identified during DDE registration in accordance with M-RPA.

4. Each DDE shall have the knowledge and authority to act on Dispatch Instructions for all ISO registered DRAs it manages for dispatch, as defined in Section VI.F of this OP - Dispatch Instructions.

    a. Any control equipment used to start, stop or vary the output of a DRR, from a remote location, shall meet the requirements relative to speed, accuracy and data channel requirements set in OP-18. Such equipment shall be maintained by the Lead MP pursuant to OP-18 and OP-2. ISO System Operators shall be notified as soon as practicable if the equipment is incapable of meeting the requirements of OP-18. The DDE shall perform the actions required to restore the equipment to normal operating conditions as soon as possible pursuant to OP-2.

    b. Each DDE shall have a dedicated voice communication telephone (assigned public switched network land line phone number) for ISO dispatching purposes unless ISO otherwise agreed to on a case-by-case basis.

5. In addition to the dedicated voice communication telephone circuit, each DDE having a total of five hundred (500) MW or more in DRRs (determined by highest capability audit value in past 12 months), shall have a dedicated automatic ringdown telephone circuit to the ISO control room unless ISO otherwise agreed to on a case-by-case basis.

6. Each DDE for a DRR that participates in the New England Markets shall have equipment capable of reliably receiving and acknowledging receipt of electronic Dispatch Instructions as frequently as necessary and to implement Dispatch Instructions in a timely manner as required by ISO Manuals and Administrative Procedures.

7. Each DDE is required to display to their DDE Operator, the following parameters for each DRR for which it is responsible, as defined in Section VI.A.6 of this OP - Equipment Requirements.

    a. ACK Required (i.e., Acknowledgement Required)

    b. Message Type

        (1) Normal

        (2) Emergency

        (3) Startup

        (4) Shutdown

    c. DDP

    d. Minimum Reduction

    e. Maximum Reduction

    f. Response Rate

    g. Unit Control Mode

    h. Heartbeat

8. Acknowledgement and response to electronic dispatch via the human machine interface of the RTU shall also be performed at the same location as the voice communications unless ISO otherwise agreed to on a case-by-case basis.

    a. Each DDE shall maintain staff on duty to communicate with ISO System Operators at all times.

    b. Each ISO CFE connected RTU shall be connected to only one DDE. This serves to limit the electronic dispatch acknowledgement to a single, approved DDE.

    c. Each DDE shall have equipment capable of reliably receiving and displaying to its operators the data in accordance with Section VI.B - Telemetering and Revenue Metering for each DRR it manages for electronic dispatch.

    d. In instances where ISO System Operators must issue Dispatch Instructions or any other operating instructions verbally, the verbal communication shall take precedence over all other forms of communication.

D. DDE - Modifying DDE Details

1. ISO evaluates each submitted DDE registration, change, or modification request according to the required lead times stated in this OP. ISO shall coordinate with each applicable Lead MP, transitioning DDE, communication vendor, and any other authorized party in order to process that request.

2. A Lead MP shall provide at least thirty (30) calendar days notice to change the DDE for a DRR, as defined in M-RPA.

    a. The effective date of the transfer shall be contingent on the proposed DDE meeting the technical requirements and being registered and approved in accordance with M-RPA.

    b. Only a DDE may submit a change request concerning the DDE communications infrastructure, moving the DDE location, or changing the contact details, in accordance with the following:

        (1) Change to a dedicated telephone number requires at least thirty (30) calendar days' advance notice.

        (2) Modification to a dedicated communication circuit (e.g., for an automatic ringdown and/or RTU) requires at least ninety (90) calendar days' advance notice.

        (3) Contact details including the person performing a role, that person's telephone number and/or email address requires at least seven (7) Business Days' advance notice.

    c. ISO approval of the change shall be contingent on ISO verification of the successful implementation and testing of the DDEs technical capabilities.

E. Emergency Message Indications

1. Each emergency message shall be displayed to each DDE with visual and audible indications:

    a. Each DRR shall have a specific "Message Type" indicator.

    b. Each DDE shall **not** employ a visual message that is common to multiple DRRs.

    c. Emergency messages shall have an audible alarm that is unique to emergency messages and **cannot** be disabled.

    d. Emergency messages are "Message Type 2" (Emergency).

e. Emergency messages that require acknowledgement shall have an "ACK Required = 1" on the RTU.

F. Dispatch Instructions

1. All Dispatch Instructions (Includes normal and emergency)

   a. If a DDE is **not** capable of controlling demand in accordance with its Offer Data, the DDE shall notify the ISO System Operators as soon as practicable. The DDE shall use its best efforts to forecast DRR capabilities based on daily local conditions and submit those parameters appropriately.

2. Normal Dispatch Instructions

   a. Normal Dispatch Instructions shall be transmitted electronically to each DDE every five minutes or less, depending on system conditions.

   b. Manual acknowledgement of a normal dispatch is **not** required; however, the DDE shall comply with the Dispatch Instruction in accordance with Offer Data without delay.

   c. Fast Start DRRs shall receive start-up and shutdown messages that the DDE shall acknowledge within sixty (60) seconds. This acknowledgement requires physical action by DDE staff. ISO may waive this requirement on a case-by-case basis. The DDE acknowledgement of a start-up or shutdown message shall indicate the DDE's intent to immediately comply with the Dispatch Instruction.

   d. Fast Start DRRs shall **not** restore load without receiving a shutdown message.

   e. 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

   a. ISO System Operators shall issue emergency messages when an emergency issue requires an immediate response by DRRs outside of the normal dispatch protocol.

   b. Emergency Dispatch Instructions shall be transmitted electronically to each DDE every five minutes or less, depending on system conditions.

   c. The DDE shall acknowledge an emergency message within sixty (60) seconds of the receipt of the message. This acknowledgement requires physical action by DDE staff. ISO may waive this requirement on a case-by-case basis. Acknowledgement of the emergency message shall indicate the DDE's intent to immediately comply with the Dispatch Instruction.

d. The DDE shall respond to an Emergency Dispatch Instruction in accordance with Offer Data without delay.

e. In an emergency, Fast Start DRRs that are called on to interrupt load shall receive an emergency message and a DDP in lieu of a start-up message. The DDP that accompanies the emergency message dictates the desired response from the DRR. The DDE shall take action to comply with the Dispatch Instructions in accordance with the DRR's Offer Data.

f. Fast Start DRR shall **not** restore load without receiving a shutdown message.

g. While the emergency message is active, voice communication to the ISO Control Room related to the Dispatch Instructions should be limited to only those pertaining to clarifying the Dispatch Instructions.

4. Operational Considerations

a. A DRR shall be dispatched as directed by ISO in accordance with OP-1, and the operating characteristics submitted by the Lead MP. The safety of operating personnel and prevention of damage to equipment are the sole responsibility of the Lead MP, and shall be the priority at all times.

b. The Lead MP or DDE, as applicable, shall maintain the DRR control equipment in good operating condition, and shall promptly report to ISO any problems interfering with its proper operation.

VII. AUDITING AND TESTING

ISO reserves the right to conduct unannounced audits or tests of a DE, Generator, DARD, DDE or DRR, to verify its compliance with the technical requirements as set forth in this OP and in accordance with Section III of the ISO Tariff. These audits may be conducted on a periodic basis or because ISO has a reason to suspect a deficiency. Onsite audits will be coordinated with the Lead MP, DE, or DDE (as appropriate) and scheduled during normal business hours. An audit will be conducted according to the following, as applicable:

- ISO New England Manual for Market Operations Manual M-11
- M-RPA
- ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources Manual M-MVDR

Failure to comply with the technical requirements of this OP may cause the Resource to be unable to perform in the New England Markets. This does **not** include compliance failures due to circumstances beyond the reasonable control of the Lead MP, such as transmission, distribution or communications outages. ISO will determine the Generator, DARD, or DRR ability to perform in the New England Markets when **not** in compliance with the requirements of this OP. Failure to perform in the New England Markets is sanctionable behavior, and subject to treatment under Section III of the ISO Tariff.

A. Revenue Metering

1. 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 Lead MP will be responsible for the expenses of the extra meter testing.

B. Equipment Maintenance

1. Each Lead MP shall keep detailed records of equipment maintenance. ISO shall have the right to review the maintenance and test record for auditing purposes to ensure that the equipment (AVR, governor, stabilizer equipment, telemetering and communication and control equipment) is maintained in good operating condition.

C. Protection Systems

1. 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, 12E and 12G reside in the appendices to this OP. Each appendix also contains an explanation of terms and instructions for data preparation of the specific form. ISO staff will review the forms for completeness, and assign a data revision number to the form if required. Market Operations Support Services shall also route completed forms NX-12, 12E and 12G to the ISO Power System Modeling Management 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. When ISO has determined the forms to be complete and accurate, the forms will be routed to the appropriate ISO departments.

IX. TRAINING REQUIREMENTS

These training requirements establish the minimum level of knowledge for DEs, DDEs, and applicable Lead MP personnel of ISO procedures, processes, tasks and requirements applicable to participation in normal, abnormal and emergency communications with the ISO control room System Operators.

A. Applicability

1. These training requirements are applicable to DEs, DDEs, and applicable Lead MP personnel responsible for performing any of the following tasks:
   a. Communicating verbally with the ISO control room System Operators
   b. Acknowledging and/or responding to verbal or electronic Dispatch Instructions
   c. Receiving and acknowledging Emergency Notification System (ENS) messages
   d. Performing redeclaration of Generator, DARD, or ATRR operational parameters and/or availability
   e. Performing resubmittal of DRR operational parameters and/or availability

B. Required Training Modules

1. ISO develops/revises training modules annually and establishes which modules shall be completed by DEs, DDEs, and applicable Lead MP personnel in order to satisfy initial and continuing training requirements as described in Section IX.C below.
2. ISO shall make training modules available to DEs, DDEs, and applicable Lead MP personnel **no** later than May 1 of each year.
3. ISO Operational Performance, Training & Integration personnel shall communicate the specific training modules that require completion to DE training contacts, DDE training contacts, and Lead MP contacts.

C. Initial and Continuing Training Requirements

1. DEs, DDEs, and applicable Lead MP personnel must complete modules designated as initial training prior to performing any of the tasks described in Section IX.A above.
2. DEs, DDEs, and applicable Lead MP personnel shall complete modules designated for continuing training yearly, between the time new/updated training modules are made available and December 1 of the corresponding year.
3. DEs, DDEs, and applicable Lead MP personnel completing initial training between December 1 of the previous year and prior to the release of

new/updated training modules in the current year, shall still complete the new/updated training modules designated for continuing training in the current year.

4. There are **no** exemptions to meeting training requirements.

D. Completing Required Training

1. ISO shall make required training available for completion through the ISO Training & Events Network (ISO-TEN) as web-based training.
2. In addition to web-based training, ISO shall offer instructor-led training.
3. DE training contacts, DDE training contacts, and Lead MP contacts shall communicate training requirements to applicable personnel.
4. The Lead MP shall track completion of the initial and continuing training requirements for all applicable personnel.
5. Upon successful completion of required training, ISO will provide applicable personnel with a training completion certificate.

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
- -	09/19/16	For previous revision history, refer to Rev 20 available through Ask ISO;
Rev 21	05/02/14	Added new section for Alternative Technology Regulation Resource criteria and requirements; modified Section II language clarifying description and criteria of SOGs
Rev 21.1	05/23/14	Clerical change (due discovery or a typographical error) to restore committee approved language inadvertently deleted during reformatting of document in Rev 21.
Rev 22	11/07/14	Clarify language in Section II and II.I, Governor Control;
Rev 23	01/29/15	Added language to Section III.A.5 regarding notification timing criteria for change requests to ATRR dispatch methods
Rev 24	11/16/15	Added new reference for MOD-032 compliance guidance; Errata corrections on pp.17,18; Section II.A.2: added clarifying language for Common Collectors; Section II.A.6: added language for NERC Reliability Standard MOD-032 compliance;
Rev 24.1	09/19/16	Periodic review performed requiring no content changes; Added required corporate document identity to all Footers; Truncated the Revision History per SOP-RTMKTS.0210.0010 Section 5.6;
Rev 25	01/17/17	Reference Section added new reference for MOD-026 and MOD-027 compliance guidance document; Section II.A.6: clarified requirements for providing Dynamics Models data; Sub-Section X.B (and sub-steps), deleted entire sub-section and re-numbered remaining sub-sections and the attribution in new sub-step X.C.1; Globally removed outdated language and references;
Rev 26	12/11/17	Globally editorial changes to be consistent with current "accepted current practices and management expectations"; Added new Section VIII, Technical Requirements for Demand Response Resources (DRR); Identified sections no longer effective after June 1, 2018; Added new Section XII, Training Requirements;
Rev 27	11/07/18	Performed periodic review: Updated OP-5 title (globally); Globally editorial changes to be consistent with current "accepted current practices and management expectations"; Section II, modified Technical Requirements for Generators, sub-section A, Generator Defined, #6 Item 1; sub-section I. Governor Control items 1 & 4; and sub-section K, System Protection, item 3; Sections VI, VII and XI were deleted, no longer applicable post-PRD effective date of June 1, 2018 and renumbered remaining sections;