ISO New England Manual for

Market Rule 1 Accounting

Manual M-28

Revision: 60
Effective Date: March 1, 2017

Prepared by
ISO New England Inc.

ISO New England Manual for

Section 1: Market Accounting Overview

1.1 Market Accounting Overview

The ISO calculates Charges and Credits that are allocated among the Governance Participants. The ISO provides accounting for the following markets and services: Day-Ahead Energy Markets and Real-Time Energy Markets, Day-Ahead and Real-Time Net Commitment Period Compensation, Transmission Congestion costs, Transmission Losses costs, Emergency Energy, Inadvertent Interchange, Financial Transmission Rights/Auction Revenue Rights, Regulation, Real-Time Reserve, Forward Reserve Market, Forward Capacity Market and the Data Reconciliation Process. Accounting for Real-Time Reserve and the Forward Reserve Market is addressed in ***ISO New England Manual for Forward Reserve and Real-Time Reserve, M-36***.

Market accounting is designed to operate on a balanced basis. That is, the total amount of the Charges equals the total amount of the Credits; there are no residual funds. With certain exceptions, each of the services also operates on a balanced basis. That is, the Charges and Credits for a particular service, such as Regulation, offset each other exactly. In certain cases, such as transmission congestion and transmission losses, Charges in excess of Credits, or vice versa, may occur, in which case, these mismatches are reconciled on a hourly basis in the case of transmission losses, and on an annual basis in the case of transmission congestion.

Market Rule 1 Appendix A, under all applicable Sections of this manual.

1.1.1 Accounting Input Data

Section 2: Reserved

For Market Participants, for the Day-Ahead Energy Market, the Day-Ahead Load Obligation and Generation Obligation for each specific Location, for each settlement interval are described in Market Rule 1, Section III.3.2.1.

For Market Participants, for the Real-Time Energy Market, the Real-Time Load Obligation and Generation Obligation for each Load Zone, or Node in the case of an Asset Related Demand, for each settlement interval are described in Market Rule 1, Section III.3.2.1.

3.1.1 Transmission Customer Accounting

This section of the manual describes the accounting treatment of Non-Mark flow and the difference in the two External Node LMPs and the ISO Charges/Credits the Transmission Customer directly for these costs.

3.1.2 Internal Bilateral Transactions

There are currently two types of Internal Bilateral Transactions that Market Participants may enter into that are supported by the ISO: Internal Bilateral for Market, which may be associated with Energy or Forward Reserve, and Internal Bilateral for Load. In addition, Market Participants may transfer Capacity Load Obligations through a Capacity Load Obligation Bilateral Transaction, which must be submitted by noon of the second Business Day after the Obligation Month to be included in the initial settlement of payments and charges associated with the Forward Capacity Market.

Please see the ***User Guide For Submitting Internal Bilateral Transactions via SMS*** for a description of the mechanics involved in the submittal of an Internal Bilateral Transaction.

Market Participants may enter into Internal Bilaterals for Market associated with Energy in either the Day-Ahead Energy Market, in which case the transaction automatically carries forward into the Real-Time Energy Market, or just the Real-Time Energy Market. Valid settlement Locations for Internal Bilaterals associated with Energy y Market. [4BT1 0 0 1 5341BT1 0 0 1 4

In addition to the Internal Bilateral Transactions described above, Market Participants may share ownership in Generator Assets or Load Assets and may change their Ownership Shares of these assets, by mutual agreement.

3.1.3 External Transactions

The settlement treatment for External Transactions is summarized in Table 3.1.

3.1.5 Real-Time Energy Market

Real-Time Energy Market is settled in accordance with Market Rule 1 Section III.3.2.1.

Section 4: Reserved

6.1(1) of this manual. The ISO will true up any amounts drawn for Congestion Shortfalls on a monthly basis and reflect that true up in the Customer Bill reflecting non-hourly charges (the Monthly Services Customer Bill). If the Congestion Fund remains deficient at the end of the month, the process outlined in Section 6.3.3 of this manual will be followed.

(3) Positive FTR Target Allocations are determined and totaled for each FTR Holder for each hour of the month and negative FTR Target Allocations are identified and included in Monthly Transmission Congestion Revenue.

(4) Monthly Transmission Congestion Revenues, calculated as the sum of Transmission Congestion Revenue for the current month are allocated to FTR Holders as Transmission Congestion Credits based on positive FTR Target Allocations.

(5) Any excess Monthly Transmission Congestion Revenue that remains unallocated is carried forward to the end of the calendar year. At the end of the calendar year, any excess Monthly Transmission Congestion Revenue is distributed first to FTR Holders that were paid less than their positive Target FTR Allocations and then pro-rata to Market Participants who paid Congestion Costs during the year.

6.2 Transmission Congestion Revenue

Transmission Congestion Revenue is calculated in accordance with Market Rule 1 Section III.5.2.5.

6.3.4.1 ISO

annual FTR Target Allocation Deficiencies. If the excess Monthly Transmission Congestion Revenue remaining at the end of the calendar year is greater than or equal to the total annual FTR Target Allocation Deficiency, each FTR Holder is credited its annual FTR Target Allocation Deficiency and the ISO reduces the excess Monthly Transmission Congestion Revenue by these amounts. If the excess Monthly Transmission Congestion Revenue remaining at the end of the calendar year is less than the total annual FTR Target Allocation Deficiency, then the excess Monthly Transmission Congestion Revenue allocated to each FTR Holder is equal to that FTR

Monthly Transmission Congestion Revenue and divided by the total annual FTR Target Allocation Deficiency.

(2) If there is any excess Monthly Transmission Congestion Revenue remaining after the above distribution, the ISO distributes that remaining excess to Market Participants or Transmission Customers in proportion to their total yearly net Congestion Costs paid as follows:

Market Participant Excess Monthly Transmission Congestion Revenue Credit =

*annual excess Monthly Transmission Congestion Revenue * ((Market Participant's Net Congestion Costs) / (sum of Net Congestion Costs))*

Non-Market Participant Transmission Customer Excess Monthly Transmission Congestion Revenue Credit =

*annual excess Monthly Transmission Congestion Revenue * ((Non-Market Participant Transmission Customer Net Congestion Costs) / (sum Net Congestion Costs))*

Where,

Market Participant Net Congestion Costs = the sum of the Market Participant's annual Day-Ahead Energy Market Congestion Charge/Credit and annual Real-Time Energy Market Deviation Congestion Charge/Credit where this sum is a negative value, otherwise this value is equal to zero, and

Non-Market Participant Transmission Customer Net Congestion Costs = the sum of the Non-Market Participant Transmission Customer's annual Real-Time Energy Market Congestion Charge/Credit where this sum is a negative value, otherwise this value is equal to zero.

Section 7: Transmission Losses Accounting

7.1 Transmission Losses Accounting Overview

Accounting for transmission losses involves the following process:

(1) *Transmission Loss Charges/Credits for Market Participants or Transmission Customers* Market Participants with settlement accounts for the Energy Market are charged/credited for losses on the PTF portion of the New England Transmission System in both the Day-Ahead Energy Market and Real-Time Energy Market on the basis of the Loss Component of the Day-Ahead and Real-Time LMPs, such Charges/Credits for losses as calculated under Section 3 of this manual. Other Transmission Customers are charged/credited for losses on the PTF portion of the New England Transmission System in Real-Time Energy Market on the basis of the Loss Component of the Real-

7.2 Loss Revenue

The Loss Component of Day-Ahead and Real-
security constrained dispatch software and represents the cost of Marginal Losses, in $/MWh, at each Location relative to the reference point. Day-Ahead and Real-Time Loss Revenue is created as a result of the fact that the Loss Component is based upon the cost of the most expensive Marginal Loss MW, as opposed to the average cost of losses. This Loss Component calculation will tend to over-collect the amount of dollars required to fully compensate Market Participants with Day-Ahead Generation Obligations or positive Real-Time Generation Obligation Deviations.

Loss Revenue is calculated in accordance with Market Rule 1 Section III.3.2.1.

Section 8: Emergency and Security Energy Accounting

8.1 Emergency Energy Accounting Overview

The ISO may purchase Energy from outside the New England Control Area, either directly or through a purchase from a Market Participant, as needed to alleviate or end an Emergency related to a reserve deficiency condition or may sell Energy to another Control Area as requested during Emergency reserve deficiency conditions in that Control Area.

Emergency sales to other Control Areas are priced in accordance with the agreements between the ISO and the other Control Areas regarding such emergency sales.

8.2 Emergency Energy Purchases

Emergency purchase Charges (costs in excess of the costs that would have been incurred using the Real-Time LMP at the External Node or Nodes as the price for the Emergency purchase from Market Participants or directly from other Control Areas) are calculated and allocated in accordance with Market Rule 1 Section III.3.2.6.

8.3 Emergency Energy Sales

Emergency sale revenues, excluding any NCPC or other Ancillary Service Charges, in excess of the revenues, calculated using the Real-Time LMP at the External Node or Nodes that are associated with emergency sales to other Control Areas are calculated and allocated in accordance with Market Rule 1 Section III.3.2.6.

8.4 New Brunswick Security Energy Accounting Overview

8.5 New Brunswick Security Energy and Security Energy Transaction Purchases by the ISO

New Brunswick Security Energy purchase costs in excess of the External Nodal Price, associated with ISO purchases directly from the New Brunswick System Operator are allocated to Participants in proportion to their pro-rata shares of Regional Network Load for the month in which the New Brunswick Security Energy was purchased. When the External Nodal Price exceeds the New Brunswick Security Energy purchase costs, the difference will be accounted for through the Marginal Loss Revenue Fund as provided in Market Rule 1 Section III.3.2.1.

Security Energy Transactions form Market Participants pursuant to ***ISO New England Manual for Market Operations, M-11*** and ISO New England Operating Procedure No. 9 Scheduling and Dispatch of External Transactions (OP9) shall be treated in the same manner as other Dispatchable or Fixed External Transactions for Settlement purposes.

8.5.1 ISO Actions

(1) The ISO retrieves the following information:

(a) -rata share of Regional Network Load.
(b) ISO New Brunswick Security Energy purchases from the New Brunswick System Operator (in megawatts per hour).
(c) The LMP at the Salisbury 345-kV External Node.
(d) The applicable clearing price in the New Brunswick Control Area.
(e) Actual ancillary services costs and transmission costs reasonably associated with the delivery of Security Energy pursuant to the applicable tariffs.

(2) The ISO calculates the total Charges to be allocated among Participants for each New Brunswick Security Energy purchase for each hour as:

New Brunswick Security Energy Purchase Charge =

Charges from the purchase of New Brunswick Security Energy in excess of the LMP at the Salisbury 345-kV External Node

(3)

Section 9: Data Reconciliation and Requested Billing Adjustment for Meter Data Error Accounting

9.1 Resettlement Data Reconciliation Process

Meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month are reconciled by the ISO

(b) In order for the ISO to accept revisions to Tie Line Assets that affect one or more Host Participant Assigned Meter Readers, the affected Host Participant Assigned Meter Readers must agree to the revisions. The Host Participant Assigned Meter Reader who is the Assigned Meter Reader for the Tie Line Asset will initiate an e-mail to the other Tie Line Asset owners that are Host Participant Assigned Meter Readers asking that they accept the change to the asset value. The affected Host Participant Assigned Meter Readers will then respond with a confirming e-mail indicating their consent to submit the revised Tie Line Asset values to the ISO. The Host Participant Assigned Meter Reader who is the Assigned Meter Reader will forward the confirming e-mails to the ISO with the revised Tie Line Asset values. In the event that the affected Tie Line Asset is to the PTF, rather than another Metering Domain, the Host Participant should direct the e-mail requesting consent to the ISO Market Support Services Department (custserv@iso-ne.com). The ISO will then respond with a confirming e-mail indicating their consent.

(9) On or before 5:00 p.m. on the 65th day, the Host Participant Assigned Meter Reader may submit preliminary settlement data for Profiled Load Asset data.

(10) After the 65th day, the ISO will not accept any revisions to the Directly Metered Asset data for use in the meter reconciliation re-settlement process.

(11) On the 66th day, the ISO will provide a report to the Host Participant Assigned Meter Reader for all Metering Domains for which the Host Participant Assigned Meter Reader is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to day 66.

(12) On the 66th day, the ISO will provide a report to the Directly Metered Asset Owners reflecting the latest Directly Metered Asset data, by Asset ID, submitted to the ISO prior to day 66.

(13) Prior to 5:00 p.m. on the 70th day, the Market Participant or its DDE must submit meter data or load reduction values for all On Peak Demand Response Assets, Seasonal Peak Demand Response Assets, Real-Time Demand Response Assets and Real-Time Emergency Generation Assets, as detailed in the Data Requirement Matrix for Demand Resources in Section 12.3.3 of this manual.

(14) Prior to 5:00 p.m. on the 85th day, the Host Participant Assigned Meter Reader must submit meter data for all Profiled Load Assets and Peak Contribution values for all Load Assets.

(15) On the 86th day, the ISO will provide a report to the Profiled Load Asset Owners reflecting the latest Profiled Load Asset data, by Asset ID, submitted to the ISO prior to day 86.

(16) On the 86th day, the ISO will provide a report to the Host Participant Assigned Meter Reader for all Metering Domains for which the Host Participant Assigned Meter Reader

is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to day 86.

(17) On or before 5:00 p.m. on the 90th day, the Profiled Load Asset Owners must review the Profiled Load Asset data and notify the Host Participant Assigned Meter Reader, for the applicable Profiled Load Asset, of any issues that they identify with the Profiled Load Asset data. Any issues identified and submitted to the Host Participant Assigned

9.2 Resettlement

(c) Directly Metered Asset changes that result from changes to other Directly Metered Asset that met either criterion in (a) or (b) above.

The submittal process for the data is as follows:

(i

(b) Profiled Load Asset changes for assets speci

Section 10: Inadvertent Interchange Accounting

10.1 Inadvertent Interchange Accounting Overview

Settlement treatment of Inadvertent Interchange is described in Market Rule 1 Section III.3.2.1.

Section 11: Reserved

Section 12: Real-Time Settlement Quantities and Procedures

12.1 Overview

In order for the settlement of the Real-Time Energy Market to occur properly, all Market Participants are required to account for all physical generation and load within the New England Control Area and to identify applicable tie lines within and external to the New England Control Area that are needed for load calculation purposes. This is accomplished through the creation of Load Assets, Generation Assets and Tie-Line Assets that are registered w

each Load Asset and Generator Asset is identified with a Location at which it will settle in the Real-Time Energy Market.

Once these assets are registered, they are incorporate

System Model which is the model used by the ISO to calculate Real-Time Generation Obligations and Real-Time Load Obligations. The Settlement Power System Model includes all Generator Assets and Load Assets along with their associated settlement Location, and Tie-Line Assets. All three of these assets are utilized within the Settlement Power System Model to ensure that all generation provided into the system and all load consumption is accounted for.

The following sections describe the Settlement Power System Model and the calculation of Real-Time Load Obligation.

12.2 Settlement Power System Model for SMS

The Settlement Power System Model is the model that is utilized by the Settlement Market

(2) Have one Unmetered Load Asset that is used to balance each Metering Domain with respect to other Load Assets, Generation Assets and Tie-Line Assets connected to the Metering Domain.

Depending upon the modeling of any other Load Assets connected to a particular Metering Domain the normal balancing quantity assigned to the Unmetered Load Asset may be zero or a portion of the Metering Domain load.

12.2.3 Tie-Line Assets

Tie-Line Assets are created for the purposes of making physical connections between Metering Domains or between a Metering Domain and the PTF within the Settlement Power System Model. In addition, Tie-
Inter-State -
in this section. For each Tie 48.6 Tm oiBT/F6F6 12 Tf07 13[12 Tf267 6 Tm Metering D Tm o

(6) Each Asset Related Demand will be assigned a unique asset ID by the ISO. Information regarding Asset Related Demand eligibility is provided in Section 1.3 of ***ISO New England Manual for Registration and Performance Auditing, M-RPA***.

(7) Only one Unmetered Load Asset will be modeled for each Metering Domain. The Unmetered Load Asset will be calculated by the ISO as described under the Unmetered Load Asset Section below. The Unmetered Load Asset cannot be used to model Asset Related Demand, Metering Domain Loss Correction or station service load (unless the station service load is for a 345-kV connected Generator which has its own Metering Domain).

The following section describes the various types of loads included within a Load Asset and any special modeling requirements:

12.2.5.1 Load Other Than Asset Related Demand

This is Energy that is utilized to serve non-dispatchable customer loads that are settled at a Zone. Typically individual customers are not modeled and reported as individual Load Assets but are normally combined with non-PTF losses and other customer loads in the formation of a Load Asset. Load Assets representing customer load settle at the Zonal Price of the Load Zone they are associated with. Customers shall be included within Load Assets based on the following guidelines:

(1) Load Zones - Inter-State Border Arrangements

Customers of one Distribution Company may be served electrically by facilities owned and operated by another Distribution Company in a neighboring State/Reliability Region. In these circumstances, Intra Market Participant Tie-Line Assets or Tie-Line Assets have and will be established to account for the transfer of energy between the companies. These customers will be mapped to the appropriate Load Zone within the state where the Distribution Company of record (i.e., the distribution company responsible for billing the customer for distribution service) operates.

(2) Load Zones Intra-State Border Arrangements

Customers of a single Distribution Company may be served electrically from facilities located in different Reliability Regions. In these circumstances Tie-Line Assets have or will be established to account for the transfer of energy between the Reliability Regions/ Load Zones. Each individual customer served by the Distribution Company will be designated to the appropriate Load Zone based on the normal supply facility (substation, feeder and transformer) designation listed in the Distribution Companies operational and/or customer information systems. These customers will be mapped electrically to the appropriate Load Zone.

(3) Mapping Customers to Load Zones

Mapping individual customers to Load Zones and reporting aggregated Load Zone quantities for settlement is the responsibility of the Host Participant Assigned Meter Reader.

12.2.5.2 Station Service (unit shut down) Load

Station service load is energy utilized by generating or storage facilities when not delivering net generation to the power grid. This load may include energy while a unit is economically dispatched off-line, on a maintenance outage, starting up or shutting down. This type of load does not include energy utilized for the construction of new facilities. Station service loads may be modeled as an Asset Related Demand in the Power System Model if they meet the Asset Related Demand eligibility criteria. Otherwise, station service load must be reported as part of load described under Section 12.2.5.1 of this manual.

12.2.5.3 Asset Related Demands and Dispatchable Asset Related Demands

Each Asset Related Demand must be modeled in the Settlement Power System Model as a Load Asset. Asset Related Demand will settle at the nodal price of the Node to which they are connected within the Settlement Power System Model. Pumping load is Energy utilized in the pumping mode for a Market Participant pumped storage hydroelectric facility and may be registered as an Asset Related Demand if they meet the Asset Related Demand eligibility criteria.

Information regarding Asset Related Demand eligibility is provided in Section 1.3 of ***ISO New England Manual for Registration and Performance Auditing, M-RPA***.

12.2.5.4 Demand Resources

Demand Resources will be modeled as Load Assets for the purposes of determining the amount of interruption provided. Actual Energy consumption associated with these Demand Resources will be included within the meter data submission associated with the appropriate Load Assets that are utilized for the calculation of Real-Time Load Obligation.

12.2.5.5 Metering Domain Loss Correction

12.3 Data Submission Timing and Responsibilities

12.3.1 Responsibilities

The Assigned Meter Reader, Host Participant Assigned Meter Reader, Lead Market Participant and the ISO are all responsible for providing the daily metering data required to carry out the Real-Time Energy Market and the Forward Capacity Market settlements.

The Assigned Meter Reader and Host Participant Assigned Meter Reader responsibilities include:

(1) The reporting of hourly energy quantities for Load Assets, Generator Assets and Tie-Line Assets. All asset data must be derived from metering that is compliant with ISO New England Operating Procedure 18 requirements and must be reported in accordance with the sign conventions and requirements established in Section 12 of this manual, under Settlement Power System Model.

(2) The reporting of meter reconciliation data for use in Data Reconciliation Accounting (see Section 9 of this manual) for Load Assets, Tie-Line Assets and Generator Assets in accordance with the Data Correction Deadline for use in Data Reconciliation Accounting (see Section 9 of this manual).

(3) The prompt reporting of any discovered metering, calculating or reporting errors with respect to an asset to the ISO and the Market Participant(s) owning or having rights to the asset. Discovered errors involving a Tie-Line Asset must be reported by the Assigned Meter Reader to both parties to whom the Tie-Line Asset is connected.

The Lead Market Participant responsibilities for the type of data required and its reporting frequency is established in the ***ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources, M-MVDR***. The requirements for the timing of said data submission are provided in Section 12.3.2, below.

12.3.2 Timing

(1) The Assigned Meter Reader, Host Participant Assigned Meter Reader and ISO provide the following data within the timelines described below:

(a) By 0800 of the next Business Day following the Operating Day, the ISO provides loss data for which it is the Assigned Meter Reader to the appropriate Market Participants. If the ISO fails to provide this data by the time frame indicated, the deadline for Host Participant Assigned Meter Reader daily settlement data submission will be delayed by one hour for each hour that the data is delayed but in no case will the deadline for Host Participant Assigned Meter Reader daily settlement data submission be extended beyond the beginning of hour 1700 three Business Days after the Operating Day.

(h) By 1800 on the tenth calendar day prior to the start of the Capacity Commitment Period, using the procedures described in Attachment C to ISO New England Manual M-20, the Host Participant Assigned Meter Reader shall report estimates of

Commitment Period. The submitted Coincident Peak Contribution values shall be dated May 1 of the current calendar year. This annual submittal of Coincident Peak Contribution values is used to establish estimates of customer Capacity Requirements for the upcoming Capacity Commitment Period and is separate from the requirement to submit Coincident Peak Contribution value0.58 1e requirement to submit

Demand Resource Type	Metering Configura tion	Telemetry Required	Data Requirement	Entity Responsible for Submission and ISO User Interface	Initial Settlement Submittal

12.4.4 Real-Time Load Obligation at the Hub

-Time Load Obligation at the Hub shall be equal to the Market -Time Load Obligation associated with Internal Bilateral Transactions for Load that settles at the Hub.

12.4.5 Real-Time Generation Obligation at a Node

-Time Generation Obligation at a Node shall be equal to the d to the ISO by the Assigned Meter Reader for the Generator connected at that Node.

12.4.6 Real-Time Generation Obligation at an External Node

-Time Generation Obligation at an External Node shall be equal to the Market Participa External Node.

Section 13: Reserved

-Scheduled generating Resources that may be eligible for Operating Reserve Credits.

-Scheduled Resources. Deletes a reference to an obsol

to reflect the new Day-Ahead Operating Reserve Credit eligibility criteria. Revises the third paragraph of the Section to reflect the new Real-Time Operating Reserve Credit eligibility criteria.

calculation of Day-

Run Time is satisfied any 0LQLPX

deadline for Host Participant submission of daily settlement data if the ISO fails to provide the data by the deadline.

Participant to make that deadline independent of the submission of the same data to the ISO.

the Host Participant be obtained within the 37-hour reporting period.

Revision: 11 - Approval Date: June 11, 2004

<u>Section No.</u> <u>Revision Summary</u>

associated with Load Response Program(s) as 1300 hours on the third business day after the Operating Day.

The following six revisions are effective as of July 1, 2004.

weekly billing of the Energy Market(s).

ion of revised data so that data can be submitted prior to the release of the Customer Bill for the affected Operating Day and deletes language concerning revised settlements of monthly bills.

ills to recognize weekly billing.

The following revisions are contingent upon FERC acceptance of corresponding revisions to Appendix F of Market Rule 1 to be filed by NEPOOL.

n of a Real-Time Commitment Period will, except for Fast Start Generators, commence with the first hour during which the Resource reaches 75% of its Economic Minimum Limit.

when a Resource is ramping up to or down from a Self-Schedule are Self-Scheduled hours.

Revision: 14 -	Approval Date: June 28, 2004
Section No.	Revision Summary

	Revises the data submittal descriptions and deadlines as appropriate to describe the Data Reconciliation Process enhancements. 9.3. Adds two new subsections which describe the data submittal descriptions and deadlines for the Meter Data Error RBA process. A new subsection was added which contains applicable language from the deleted subsection 9.1.2.

Revision: 29 -	Approval Date: October 12, 2007
Section No.	Revision Summary
	-

Revision: 30 -	Approval Date: October 12, 2007
Section No.	Revision Summary
	-
8.5.1(1)(c) and	

Revision: 31

12.3.2(2)(a), (3)(a)&(3)(b)..	Deletes items (2)(a), (3)(a) and (3)(b) from Section 12.3.2. Section 12.3.3

Revision: 39 - Approval Date: October 15, 2010

(6)	
2.6.	Adds the calculation for Reserve Zone Forward Reserve Failure-to-Activate Penalty. Reserve Market cost allocation methodology.

Revision: 42 -	Approval Date: January 20, 2012
<u>Section No.</u>	<u>Revision Summary</u>
	sentence.

	the Non-Qualifying Energy Blocks definition for off-line Forward Reserve Resource Generators, on-line Forward Reserve Resource Generators and Dispatchable Asset Related Demand.

Revision: 45 -	Approval Date: December 7, 2012
Section No.	Revision Summary
3.1.2	

2.2.2.1(1) &	d and Offered CLAIM30 values used in the Forward Reserve Available Megawatts calculations.

Revision: 49 -	Approval Date: November 2, 2012
Section No.	Revision Summary
	Deletes reference to ISO New England Manual M-20 me: NoveETBT1 0 0 1 128.66 604.5vme:

	Deletes this subsection.
This set of revisions was approved on November 7, 2014	
2.2.1.1(1) &	
	Deletes the reference to ISO New England Manual for Billing, M-29.

Revision: 56 -	Approval Date: May 2, 2014
Section No.	Revision Summary

9.1.1(2) & (3). .Deletes the previous Section 12.2.5(7) language.

1.1(10)	Deletes these subsections. ŸḾMQyBįç@cC.Ć-ĿWþ4ŀaeF35ŠTU&aeŠÐb PłmÆ@%W0PŁ` Relocates this section to ISO New England Manual for Forward Reserve and Real-Time Reserve, M-36. -Ahead Energy Market, the Day-Ahead Load Obligation and Generation Obligation for each specific Location, for each settlement interval are described in Marke

ŁEW0ĚE HY@UA0•A)\

emergency sales to other Control Areas are calculated and allocated in accordance

Deletes this subsection.

8.5