SECTION III
MARKET RULE 1

APPENDIX F
NET COMMITMENT PERIOD COMPENSATION ACCOUNTING

APPENDIX F

NCPC ACCOUNTING

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NCPC ACCOUNTING

III.F.1. General.

For purposes of NCPC calculations:

a. Effective Offers. An Effective Offer for a Resource is (1) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to commit the Resource, (2) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to dispatch the Resource at a Desired Dispatch Point above its Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit, and (3) the Day-Ahead Ancillary Services Offer is subject to the following conditions:

i. The Effective Offer used in making the decision to commit the Resource establishes the parameters used for NCPC calculations, including the quantity and price pairs for output, demand reduction, or consumption up to the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit; the Start-Up Fee, No-Load Fee, or Interruption Cost; and the operating limits.

ii. In the event the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit is increased after the decision to commit the Resource, the energy price parameter for output, demand reduction, or consumption at the Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit used in making the decision to commit the Resource will be applied as the energy price parameter for additional output, demand reduction, or consumption up to the increased Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit.

iii. In the event a Minimum Generation Emergency is declared, the Economic Minimum Limit will be replaced with the Emergency Minimum Limit for purposes of determining the energy price parameter of the Effective Offer.

iv. The Effective Offer takes account of any mitigation applied to the Supply Offer and the Day-Ahead Ancillary Services Offer, whether performed prior to or after the commitment or dispatch decision is made.

v. The Effective Offer takes account of a reduction in the energy price parameter, the Start-Up Fee, the No-Load Fee, or the Interruption Cost in a Supply Offer or Demand Reduction Offer; or an increase in the energy price parameter of a Demand Bid that is made prior to the end of the Resource's Commitment Period.

vi. In the event the ISO approves the Resource's synchronization to the system as a Pool-Scheduled Resource earlier than its scheduled time, the Effective Offer takes account of the lesser of the energy price parameter, the Start-Up Fee and the No-Load Fee in place for the scheduled Commitment Period or the actual early release-for-dispatch time.

vii. A Resource that is online providing synchronous condensing is considered to be in a hot temperature state for the purpose of determining the Start-Up Fee for the Effective Offer when the Resource is requested to switch from synchronous condensing to provide energy.

viii. The Effective Offer takes account of cost verification performed under Sections III.1.8.1 and III.1.9.1.

ix. The energy price parameter of the Effective Offer for a Demand Response Resource is the energy price parameter submitted in the Demand Reduction Offer, even where the Demand Reduction Threshold Price is used to clear the market pursuant to Section III.1.10.1A(e)(ii).

b. Treatment of Self-Schedules.

i. In the Day-Ahead Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to the minimum of the Energy Offer Floor and the Day-Ahead Locational Marginal Price; or, in the case of a Storage DARD, is treated as having a Demand Bid with an energy price parameter for consumption up to its Minimum Consumption Limit equal to the maximum of the Demand Bid Cap and the Day-Ahead Locational Marginal Price. Any amounts (MW) offered or bid above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid.

ii. In the Real-Time Energy Market, a Resource that is committed as a Self-Schedule is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to $0/MWh; or (ii) as having a Demand Bid for consumption up to the Minimum Consumption Limit at the Demand Bid Cap. Any amounts (MW) offered above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid. For any hour for which a Resource is dispatched pursuant to Section III.1.10.9(f), the Resource is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the requested amount at the Energy Offer Floor; or (ii) as having a Demand Bid with an energy price parameter for consumption up to the requested amount at the Demand Bid Cap.

iii. If the Resource's Supply Offer contains a Self-Schedule for fewer contiguous hours than its Minimum Run Time, the minimum number of additional hours required to satisfy the Resource's Minimum Run Time will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market. If the Resource is committed for one or more hours immediately prior to and contiguous with the Self-Schedule, the hours of that prior Commitment Period will be counted toward satisfying the Resource's Minimum Run Time before hours subsequent to the Self-Schedule are counted. If the Resource's Supply Offer contains two Self-Schedules separated by less than the Resource's Minimum Down Time, the hours between the two Self-Schedules will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market.

c. **Sub-Hourly Intervals.** If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

d. **Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Minimum Run Time or Minimum Reduction Time Carries Into Second Operating Day.** If a Resource that is committed in either (i) the Day-Ahead Energy Market, or (ii) the Reserve Adequacy Analysis prior to the start of the Operating Day must continue to operate across an Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for hour ending 24 of the Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day. If a Resource that is committed during the Operating Day must continue to operate across the Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the second Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day.

e. **Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Committed Prior to Day-Ahead Energy Market.** If a Resource is committed for an Operating Day prior to the Day-Ahead Energy Market, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the Operating Day at the time of the commitment is used to establish the Effective Offer for the period of the commitment.

f. **Eligibility for NCPC Credits When Performing Audits or Facility and Equipment Testing.** The Real-Time NCPC Credit calculation for a Resource performing an audit uses the Start-Up Fee, No-Load Fee, Interruption Cost, Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction in the Effective Offer applicable to the Commitment Period during which the audit is conducted, and does not take account of any increases to the Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction that take place in the course of the audit.

Market Participants are not eligible for NCPC Credits when conducting audits or Facility and Equipment Testing under the following conditions:

i. When a Market Participant requests that some hours of the commitment of a Pool-Scheduled Resource be used to satisfy an audit, and the Market Participant has changed the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit for those hours for the purpose of conducting the audit, the Market Participant is not eligible for Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the audit is conducted.

ii. When a Market Participant Self-Schedules a Resource to perform the audit, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the Self-Schedule and is not eligible for Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the audit is conducted.

iii. When a Market Participant requests that an audit be performed that requires the ISO to dispatch the Resource for the audit without advance notice to the Market Participant, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment or Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the audit is conducted.

iv. When an ISO-Initiated Claimed Capability Audit is performed pursuant to III.1.5.1.4, the Market Participant is not eligible for Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the audit is conducted if both of the following are true:

1. the Resource had a summer or winter Seasonal Claimed Capability or Seasonal DR Audit value equal to 0 MW at the beginning of the current Capability Demonstration Year, and

2. the ISO Initiated Claimed Capability Audit is the first Claimed Capability Audit that the Resource performs during that Capability Demonstration Year.

v. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Pool-Scheduled Resource, the Economic Minimum Limit (or Minimum Consumption Limit for a Binary Storage DARD) in place at the time of the commitment decision is used for calculating Real-Time Commitment NCPC Credits and the Market Participant is not eligible for Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.

vi. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Resource that Self-Scheduled, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment and is not eligible for Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.

g. Coordinated External Transactions are Not Eligible for NCPC and are excluded from NCPC Charges. Notwithstanding anything to the contrary in this Appendix F, Market Participants are not eligible to receive NCPC Credits for Coordinated External Transactions purchases or sales and shall be excluded from all NCPC Charge calculations under this Appendix F.

h. Demand Response Resource Credit Calculations. Where indicated in Section III.F.2, the costs and revenues for a Demand Response Resource, other than those associated with Net Supply or Interruption Costs, are increased by average avoided peak distribution losses.

i. Following Dispatch Instructions.

i. For the purpose of allocating NCPC costs, a Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit greater 50 MW is considered to be following a dispatch instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 10% above its Desired Dispatch Point and not less than 10% below its Desired Dispatch Point for each interval in the hour. A Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit less than or equal to 50 MW is considered to be following a Dispatch Instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 5 MW above its Desired Dispatch Point and is not less than 5 MW below its Desired Dispatch Point for each interval in the hour. If the Resource violates this criterion in any interval during the hour, the Resource is considered to be not following Dispatch Instructions for the entire hour.

ii. DNE Dispatchable Generators are considered to be following Dispatch Instructions if the actual output of the DNE Dispatchable Generator is at or below its Do Not Exceed Dispatch Point.

III.F.2. NCPC Credits

III.F.2.1 Day-Ahead Market NCPC Credits

III.F.2.1.1. Eligibility for Credit. A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a Storage DARD with a Demand Bid that clears the Day-Ahead Energy Market in an hour is eligible for Day-Ahead Market NCPC Credits for the hour.

III.F.2.1.2. Settlement Period. For a Generator Asset, a Demand Response Resource, or a Storage DARD, for purposes of calculating Day-Ahead Market NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day for which a Resource has cleared in the Day-Ahead Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator or to or from a Fast Start Demand Response Resource, or any time a DNE Dispatchable Generator's operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation.

III.F.2.1.3. **Eligible Quantity.** For a Generator Asset, Demand Response Resource, or Storage DARD, the eligible quantity of energy is the amount of energy the Resource clears in the Day-Ahead Energy Market for each hour of the settlement period.

III.F.2.1.3A **Hourly Bid.** For a Storage DARD, the hourly bid is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each hour of the settlement period.

III.F.2.1.4 **Hourly Cost for Energy.**

(a) For a Generator Asset, the hourly cost is equal to the energy price parameter for the eligible quantity, the Start-Up Fee and the No-Load Fee as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.

(b) For a Demand Response Resource, the hourly cost is equal to the energy price parameter for the eligible quantity and the Interruption Cost as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.

(c) For a Storage DARD, the hourly cost is equal to the Day-Ahead Locational Marginal Price for each hour of the settlement period multiplied by the eligible quantity.

III.F.2.1.4.1 For a Generator Asset or a Demand Response Resource, the Start-Up Fee or Interruption Cost is apportioned equally over the hours from the time the Resource is scheduled to begin its commitment through the end of the Commitment Period during which the Minimum Run Time or Minimum Reduction Time is scheduled to expire.

III.F.2.1.4.2 For a Generator Asset or a Demand Response Resource, when the period of hours over which the Start-Up Fee or Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee or Interruption Cost.

III.F.2.1.4.A Hourly Cost for Day-Ahead Ancillary Services. The hourly cost for Day-Ahead Ancillary Services is equal to the Day-Ahead Ancillary Services Offer prices as reflected in the Effective Offer multiplied by the amount of each award for each hour of the settlement period.

III.F.2.1.5 Hourly Revenue for Energy. For a Generator Asset or a Demand Response Resource, the hourly revenue is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity for the Resource, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price.

III.F.2.1.5.A Hourly Revenue for Day-Ahead Ancillary Services. For a Generator Asset, a Demand Response Resource, or a DARD, the Day-Ahead Ancillary Services hourly revenue is equal to the total Day-Ahead Ancillary Services Market Credit as calculated in Section III.3.2.1(q)(1) for each hour of the settlement period.

III.F.2.1.6 General Credit Calculation. Except as provided in Section III.F.2.1.7 below, the Day-Ahead Market NCPC Credit for a Resource, adjusted as described in III.F.1(h), is equal to:

(a) For a Generator Asset or a Demand Response Resource: the greater of (i) zero, and; (ii) the total hourly cost for Energy and Day-Ahead Ancillary Services for the Resource in all hours of the settlement period, minus the total hourly revenue for Energy and Day-Ahead Ancillary Services for the Resource in all hours of the settlement period, where the costs and revenues of a Demand Response Resource, other than those associated with Interruption Costs, are increased by average avoided peak distribution losses; and

(b) For a Binary Storage DARD: the greater of (i) zero and (ii) the total hourly cost for Energy and Day-Ahead Ancillary Services for the Resource in all hours of the settlement period, minus the total hourly bids in all hours of the settlement period and the total Day-Ahead Ancillary Services hourly revenue.

III.F.2.1.7 Credit Calculation for Fast Start Generators, Flexible DNE Dispatchable Generators, Fast Start Demand Response Resources and Binary Storage DARDs Based on Daily Starts, and for Continuous Storage Generator Assets and Continuous Storage DARDs. If either (1) the number of daily starts for a Fast Start Generator, Flexible DNE Dispatchable Generator, Fast Start Demand Response Resource or Binary Storage DARD is less than the resource's Maximum Number of Daily Starts, or (2) the resource is a Continuous Storage Generator Asset or a Continuous Storage DARD, then the resource's Day-Ahead Market NCPC Credit, adjusted as described in III.F.1(h), is calculated as follows:

(a) For a Fast Start Generator, a Continuous Storage Generator Asset, a Flexible DNE Dispatchable Generator or a Fast Start Demand Response Resource, the Day-Ahead Market NCPC Credit is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for Energy and Day-Ahead Ancillary Services for the Resource in an hour, minus the hourly revenue for Energy and Day-Ahead Ancillary Services for the Resource in that hour.

(b) For a Storage DARD, the Day-Ahead Market NCPC Credit is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the total hourly cost for Energy and Day-Ahead Ancillary Services for the Resource in an hour, minus the total hourly bid for the Resource in that hour and the total Day-Ahead Ancillary Services hourly revenue.

III.F.2.2 Real-Time Energy Market NCPC Credits. Real-Time Energy Market NCPC Credits include a Real-Time Commitment NCPC Credit, a Real-Time Dispatch NCPC Credit and a Real-Time Dispatch Lost Opportunity Cost NCPC Credit. For purposes of this Section III.F.2.2, unless otherwise expressly stated, costs and revenues shall be calculated at a five-minute interval.

III.F.2.2.1 Eligibility for Credit.

(a) Commitment Credits – The following Resources are eligible for Real-Time Commitment NCPC Credits for some or all intervals of the hour: (i) a Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market and that has been committed by the ISO; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; or (iii) a Binary Storage DARD with a Demand Bid that has been submitted in the Real-Time Energy Market and that has been committed by the ISO.

(b) Dispatch Credits – The following Resources are eligible for Real-Time Dispatch NCPC Credits for some or all intervals of the hour: (i) a Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; (iii) a Storage DARD with a Demand Bid that has been submitted in the Real-Time Energy Market; or (iv) a Storage DARD that has been Postured to increase its consumption. The Real-Time Dispatch NCPC Credit shall be zero, however, if the Generator Asset has provided Regulation during the interval.

(c) Dispatch Lost Opportunity Cost Credits – A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a Dispatchable Asset Related Demand with a Demand Bid that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Real-Time Dispatch Lost Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Generator Asset, Demand Response Resource, or Dispatchable Asset Related Demand has been Postured or has provided Regulation during the interval.

III.F.2.2.2 Real-Time Commitment NCPC Credits

III.F.2.2.2.1. Settlement Period.

(a) For Generator Assets, Demand Response Resources, and Binary Storage DARDs, for purposes of calculating Real-Time Commitment NCPC Credits, a settlement period is a period of one or more contiguous intervals in an Operating Day during which a Resource is operating pursuant to one or more commitments in the Day-Ahead Energy Market or Real-Time Energy Market.

(b) For Generator Assets and Demand Response Resources, a new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE

Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.

(c) For Generator Assets and Binary Storage DARDs, in the event of an interruption in operation of a Resource, operation will be considered contiguous if the Resource returns to operation in accordance with the original commitment issued prior to the interruption.

III.F.2.2.2.2. Eligible Quantity.

III.F.2.2.2.2.A For a Binary Storage DARD, the eligible quantity for each interval is the amount of energy equal to the lesser of its Economic Dispatch Point for that interval and its Metered Quantity For Settlement for the interval.

III.F.2.2.2.2.1.

(a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy equal to the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval; provided however, that during contiguous pricing intervals in which the Generator Asset's Economic Dispatch Point is higher than it would otherwise be as a result of an offered ramp rate limitation, then the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy for the interval equal to the lesser of: (a) the Generator Asset's Metered Quantity For Settlement; and (b) the greater of: (i) the Generator Asset's expected output level had it reduced its output per its offered ramp rate during the relevant intervals as instructed by the ISO, and (ii) the output level to which the Generator Asset would have been dispatched absent the offered ramp rate limitation.

(b) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval, except that Metered Quantity For Settlement is used as the eligible quantity (i) when the Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) when the Resource is ramping from an offline state to be released for dispatch or (iii) after the Resource has been released for shutdown.

III.F.2.2.2.2.2.

(a) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and its Economic Dispatch Point for the interval; provided however, that during contiguous pricing intervals in which the Demand Response Resource's Economic Dispatch Point is higher than it would otherwise be as a result of an offered ramp rate limitation, then the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy for the interval equal to the lesser of: (a) the Demand Response Resource's Metered Quantity For Settlement; and (b) the greater of: (i) the Demand Response Resource's expected demand reduction had it provided the reduction per its offered ramp rate during the relevant intervals as instructed by the ISO, and (ii) the demand reduction level at which the Demand Response Resource would have been dispatched absent the offered ramp rate limitation.

(b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is equal to the eligible quantity used to determine interval costs pursuant to (a) above, except that the eligible quantity shall be the Metered Quantity For Settlement if any of the following are true: (i) the Demand Response Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time have not concluded, or (iii) the Demand Response Resource has received an instruction to stop reducing demand.

III.F.2.2.2.3. Interval Cost.

(a) The interval cost for a Generator Asset is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Start-Up Fee and No-Load Fee as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1, III.F.2.2.2.3.2, and III.F.2.2.2.3.3.

(b) The interval cost for a Demand Response Resource is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Interruption Cost as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1 and III.F.2.2.2.3.2, provided that costs shall be set to $0 for the interval when there is a negative demand reduction.

(c) The interval cost for a Binary Storage DARD is the Real-Time Price for the interval multiplied by the eligible quantity. The interval cost is reduced by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval cost is also reduced by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5.

III.F.2.2.2.3.1

(a) For a Generator Asset, the energy cost for an interval excludes the cost of (a) energy produced when the Resource is ramping from an offline state to be released for dispatch and (b) energy produced after the Resource has been released for shutdown.

(b) For a Demand Response Resource, the energy cost for an interval excludes the cost of (a) energy produced prior to the conclusion of the Demand Response Resource Start-Up Time and (b) energy produced after the Demand Response Resource has received an instruction to stop reducing demand.

III.F.2.2.2.3.2

(a) For a Generator Asset, the Start-Up Fee is apportioned equally over the intervals from the time the Generator Asset is released for dispatch through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire, subject to the following conditions:

(i) The Start-Up Fee is reduced in proportion to the number of minutes after 30 the Generator Asset is released for dispatch (measured from the time the Generator Asset was scheduled to be released for dispatch), divided by the time from when the Generator Asset was scheduled to be released for dispatch through the end of the Commitment Period during which the Minimum Run Time was scheduled to expire.

(ii) The Start-Up Fee is excluded from the interval cost calculation if the Generator Asset is synchronized to the system prior to its scheduled synchronization time without the ISO's approval of the Generator Asset's synchronization as a Pool-Scheduled Resource.

(iii) The portion of the Start-Up Fee apportioned to any interval during which the Generator Asset is not online because the Generator Asset has tripped is excluded from the interval cost calculation, except in the event the Generator Asset is not online due to a trip that results from equipment failure involving equipment located on the electric network beyond the low voltage terminals of the Generator Asset's step-up transformer. It is the responsibility of the Lead Market Participant for the Generator Asset to inform the ISO at xtrip@iso-ne.com within 30 days that the trip was the result of such a transmission-related event.

(iv) The Start-Up Fee is not reduced when the Generator Asset has shutdown with the ISO's approval prior to the end of its Commitment Period.

(v) The additional Start-Up Fee for a Generator Asset requested to re-start following a trip is apportioned equally over the remaining intervals of the Commitment Period when the ISO requests a Generator Asset to re-start to complete its Commitment Period.

(vi) When the period of intervals over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.

(b) For a Demand Response Resource, the Interruption Cost is apportioned equally over the intervals from the time the Demand Response Resource Start-Up Time concludes through the end of the Commitment Period during which the Minimum Reduction Time is scheduled to expire, subject to the following conditions:

(i) The Interruption Cost is reduced in proportion to the number of minutes after 30 the Demand Response Resource begins to provide a demand reduction (measured from the conclusion of the Demand Response Resource Start-Up Time), divided by the time from the conclusion of the Demand Response Resource Start-Up Time through the end of the Commitment Period during which the Minimum Reduction Time was scheduled to expire.

(ii) The portion of the Interruption Cost apportioned to any interval during which the Demand Response Resource is not providing a demand reduction because the Demand Response Resource has become unavailable to provide a reduction is excluded from the interval cost calculation.

(iii) The Interruption Cost is not reduced when the Demand Response Resource has stopped reducing demand with the ISO's approval prior to the end of its Commitment Period. When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.

(iv) When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.

III.F.2.2.2.3.3. For a Generator Asset for each hour, the No-Load Fee is equally apportioned to each interval in the hour during the period when the Generator Asset is online following its release for dispatch and prior to its release for shutdown. The No-Load Fee is pro-rated for the hour during which the Generator Asset is released for dispatch, the hour during which the Generator Asset is released for shutdown, and any other hour during which the Generator Asset operates for less than 60 minutes.

III.F.2.2.2.3.A Interval Bid. The interval bid for a Binary Storage DARD is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each interval of the settlement period.

III.F.2.2.2.4 Interval Revenue. The interval revenue for a Generator Asset or Demand Response Resource is equal to the Real-Time Price for each interval of the settlement period multiplied by the eligible quantity for the interval. The revenue for an interval is increased by the amount by which the interval revenues in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.4 exceed the interval costs in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.3. The interval revenue is increased by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval revenue is also increased by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5. The revenues when the Generator Asset is ramping from an offline state to be released for dispatch, or during the Demand Response Resource Start-Up Time, are apportioned equally to the intervals of the Minimum Run Time or Minimum Reduction Time.

III.F.2.2.2.4.1. For a Generator Asset, revenues for output up to the Resource's Economic Minimum Limit in a Self-Scheduled interval, calculated as the Real-Time Price multiplied by the output, are excluded from the revenue for the Real-Time Commitment NCPC Credit calculation.

III.F.2.2.2.4.2. For a Demand Response Resource, revenues shall be set to $0 for the interval when the Locational Marginal Price is positive and there is a negative demand reduction.

III.F.2.2.2.5 Credit Calculation for Generator Assets and Demand Response Resources. The Real-Time Commitment NCPC Credit for a Generator Asset or a Demand Response Resource, adjusted as described in III.F.1(h) is equal to:

(a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval revenue for the Resource for the period,

plus,

(b) For each remaining interval of the settlement period following the completion of the Minimum Run Time or Minimum Reduction Time, the greater of ((i) zero, and; (ii) the maximum potential net revenues for the Resource in the period) minus the actual net revenues for the Resource in the period, where

(i) The maximum potential net revenue is the maximum accumulated net interval revenue for operating and then shutting down (or, for a Demand Response Resource, reducing demand and then ceasing to reduce demand) during the period.

(ii) The actual net revenue is the accumulated net interval revenue over the period.

(iii) The net interval revenue is the interval revenues minus interval costs in the period.

III.F.2.2.2.6. [Reserved.]

III.F.2.2.2.7 Credit Calculation for Binary Storage DARDs. The Real-Time Commitment NCPC Credit for a Binary Storage DARD is equal to:

(a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval bid for the Resource for the period,

plus,

(b) For each remaining interval of the settlement period following the completion of the Minimum Run Time, the greater of ((i) zero, and; (ii) the maximum potential net benefit for the Resource in the period) minus the actual net benefit for the Resource in the period, where

(i) The maximum potential net benefit is the maximum accumulated net interval benefit for operating and then shutting down during the period.

(ii) The actual net benefit is the accumulated net interval benefit over the period.

(iii) The net interval benefit is the interval bid minus interval cost in the period.

III.F.2.2.2.8 Resources with Commitment in the Day-Ahead Energy Market (other than Fast Start Generators, Fast Start Demand Response Resources, and Binary Storage DARDs).

(a) For purposes of calculating the interval cost under Section III.F.2.2.2.3, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or Binary Storage DARD) has a commitment in the Day-Ahead Energy Market, the Start-Up Fee, No-Load Fee, Interruption Cost and energy price parameter for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to \$0 for the hour. The Start-Up Fee shall not be set to \$0 in the case when a Resource re-starts at ISO request following a trip.

(b) For purposes of calculating the interval revenue under Section III.F.2.2.2.4, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or Binary Storage DARD) has a commitment in the Day-Ahead Energy Market, the revenue for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to \$0 for the hour if such revenue is less than \$0.

(c) Notwithstanding anything to the contrary in this Section III.F.2.2.2, a Generator Asset that cleared in the Day-Ahead Energy Market and performs an audit scheduled by the ISO pursuant to Section

III.1.5.2(f) during all or part of its Day-Ahead schedule on a higher-priced fuel than that which formed the basis of the Generator Asset's Supply Offer in the Day-Ahead Energy Market shall receive additional compensation equal to:

i. For the MW quantity equal to the lesser of the Generator Asset's actual metered output and Economic Dispatch Point, the difference between 1) the incremental energy audit costs based on the Supply Offer using the fuel on which the audit was performed and 2) amounts calculated for that same operation as reflected in the greater of the Day-Ahead Supply Offer and the cost-based Reference Levels calculated using the fuel on which the Day-Ahead Supply Offer was based; and

ii. The difference between the No-Load Fee based on the Supply Offer using the fuel on which the audit was performed and the No-Load Fee for that same operation as reflected in the Day-Ahead Supply Offer; and

iii. Any additional Start-Up Fees incurred as a result of performing the audit.

III.F.2.2.3. Real-Time Dispatch NCPC Credits for Generator Assets and Demand Response Resources.

III.F.2.2.3.1 Settlement Period.

(a) Except as provided in Section III.F.2.2.3.1(b), for Generator Assets and Demand Response Resources, for purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement for a Resource are each greater than its Economic Dispatch Point, excluding any period of time when:

   i. For a Generator Asset, the generator is ramping from an offline state to be released for dispatch, and after the generator has been released for shutdown, or

   ii. For a Demand Response Resource, prior to the conclusion of the Demand Response Start-Up Time and after the Demand Response Resource has received a Dispatch Instruction to stop reducing demand.

(b) For a Continuous Storage Generator Asset associated with an ATRR that has provided Regulation during the interval, a settlement period is an interval when the Desired Dispatch Point is greater than the Economic Dispatch Point.

III.F.2.2.3.2. Eligible Quantity.

III.F.2.2.3.2.1.

(a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Generator Asset's Economic Dispatch Point for the interval subtracted from the lesser of the Generator Asset's Metered Quantity For Settlement or Desired Dispatch Point for the interval, unless a Continuous Storage Generator Asset is associated with an ATRR that has provided Regulation during the interval, in which case the eligible quantity is the Generator Asset's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

(b) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Demand Response Resource's Economic Dispatch Point for the interval subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement and its Desired Dispatch Point for the interval.

III.F.2.2.3.2.2.

(a) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit is the Generator Asset's Metered Quantity For Settlement for the interval minus the Generator Asset's Economic Dispatch Point, except that the Generator Asset's Economic Dispatch Point subtracted from the lesser of the Generator Asset's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval. Notwithstanding the foregoing, if a Continuous Storage Generator Asset is associated with an ATRR that has provided Regulation during the interval, the eligible quantity is the Generator Asset's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

(b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit equals the Demand Response Resource's Metered Quantity For Settlement for the interval minus the Demand Response Resource's Economic Dispatch Point, except that the Demand Response Resource's Economic Dispatch Point subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval.

III.F.2.2.3.3 Interval Cost. For a Generator Asset or a Demand Response Resource, the interval cost is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer and does not include the Start-Up Fee, the No-Load Fee, or the Interruption Cost.

III.F.2.2.3.4 Interval Revenue. For a Generator Asset or a Demand Response Resource, the interval revenue is equal to the Real-Time Price multiplied by the eligible quantity.

III.F.2.2.3.5. Credit Calculation. For a Generator Asset or a Demand Response Resource, the Real-Time Dispatch NCPC Credit in an interval is equal to the greater of (i) zero and (ii) the interval cost minus the interval revenue for the Resource, adjusted as described in III.F.1(h).

III.F.2.2.4 Real-Time Dispatch NCPC Credits for Storage DARDs

III.F.2.2.4.1 Settlement Period. For purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement are each greater than the Storage DARD's Economic Dispatch Point, unless a Continuous Storage DARD is associated with an ATRR that has provided Regulation during the interval, in which case a settlement period is an interval when the Desired Dispatch Point is greater than the Economic Dispatch Point.

III.F.2.2.4.2 Eligible Quantity. The eligible quantity of energy is equal to the greater of (i) zero and (ii) the Storage DARD's Economic Dispatch Point for the interval subtracted from the lesser of the Storage DARD's Metered Quantity For Settlement or Desired Dispatch Point for the interval, unless a Continuous Storage DARD is associated with an ATRR that has provided Regulation during the interval, in which case the eligible quantity is the DARD's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

III.F.2.2.4.3 Interval Cost. The interval cost is the Real-Time Price for the interval multiplied by the eligible quantity.

III.F.2.2.4.4 Interval Bid. The interval bid is equal to the energy price parameter for the eligible quantity as reflected in the Demand Bid for each interval of the settlement period.

III.F.2.2.4.5 Credit Calculation. The Real-Time Dispatch NCPC Credit for an eligible Storage DARD in an interval is equal to the greater of: (i) zero, and; (ii) the interval cost minus the interval bid in that interval.

III.F.2.2.5. Real-Time Dispatch Lost Opportunity Cost NCPC Credits

III.F.2.2.5.1. Maximum Net Revenue or Maximum Net Benefit.

(a) For a Generator Asset or a Demand Response Resource, the maximum net revenue during the interval is the Resource's energy revenue at the Economic Dispatch Point, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point, as described in III.F.1(h).

(b) For a Dispatchable Asset Related Demand, the maximum net benefit during the interval is the Resource's energy price parameter for the Economic Dispatch Point as reflected in the Demand Bid, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point.

III.F.2.2.5.2. Actual Net Revenue or Actual Net Benefit.

(a) The actual net revenue for a Generator Asset or Demand Response Resource shall be the sum, adjusted as described in III.F.1(h), of the following two values:

(i) for a Continuous Storage Generator Asset associated with an ATRR that has provided Regulation during the interval, the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity; otherwise, the greater of: (1) the energy revenue at the Metered Quantity For Settlement minus the offered energy cost for that quantity and (2) the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity; and

(ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.

(b) The actual net benefit for a Dispatchable Asset Related Demand shall be the sum of the following two values:

(i) for a Continuous Storage DARD associated with an ATRR that has provided Regulation during the interval, the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity; otherwise, the greater of: (1) the energy price parameter for the Metered Quantity For Settlement as reflected in the Demand Bid minus the offered energy cost for that quantity and (2) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity; and

(ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.

III.F.2.2.5.3. Credit Calculation. For a Generator Asset, a Demand Response Resource, or a Dispatchable Asset Related Demand, the Real-Time Dispatch Lost Opportunity Cost NCPC Credit is equal to the greater of: (i) zero; and (ii) the Resource's maximum net revenue or benefit for the interval less its actual net revenue or benefit for the interval.

The Dispatch Lost Opportunity Cost NCPC Credit for a Resource for an interval shall be reduced by the amount of any Rapid Response Pricing Opportunity Cost NCPC Credits for which the Resource is eligible for that interval, but shall be no less than zero.

III.F.2.3. Special Case NCPC Credit Calculations

III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits

III.F.2.3.1.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction imports or Increment Offers at an External Node are eligible for Day-Ahead External Transaction Import and Increment Offer NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.1.2. Hourly Offer. The Day-Ahead offer for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the offer price.

III.F.2.3.1.3. Hourly Revenue. The Day-Ahead revenue for a pool-scheduled External Transaction import at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, subject to the conditions specified in Section III.3.2.1(q)(4)(ii). For Increment Offers at an External Node, the Day-Ahead revenue at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Locational Marginal Price.

III.F.2.3.1.4. Credit Calculation. A Day-Ahead External Transaction Import and Increment Offer NCPC Credit for an External Transaction import or Increment Offer, for an hour, is equal to any portion of the Day-Ahead offer in excess of the Day-Ahead revenue for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction import or Increment Offer for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction export or Decrement Bid for the same External Node and hour, the Day-Ahead External Transaction Import and Increment Offer NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction import or Increment Offer at the External Node for the hour that is not offset by the amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour. If multiple External Transaction imports or Increment Offers at an External Node are eligible for a Day-Ahead External Transaction Import and Increment Offer NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction imports and Increment Offers will be offset in order from the highest to the lowest-priced transactions or offers.

III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits

III.F.2.3.2.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction exports or Decrement Bids at an External Node are eligible for Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.2.2. Hourly Bid. The Day-Ahead bid for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the bid price.

III.F.2.3.2.3. Hourly Cost. The Day-Ahead cost for a pool-scheduled External Transaction export at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price at the External Node, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price. For Decrement Bids at an

External Node, the Day-Ahead cost at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Locational Marginal Price.

III.F.2.3.2.4. Credit Calculation. A Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for an External Transaction export or Decrement Bid, for an hour, is equal to any portion of the Day-Ahead hourly cost in excess of its Day-Ahead hourly bid for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction export or Decrement Bid for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction import or Increment Offer for the same External Node and hour, the Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour that is not offset by the amount (MW) of the total cleared External Transaction import or Increment Offer at the External Node for the hour. If multiple External Transaction exports or Decrement Bids at an External Node are eligible for a Day-Ahead External Transaction Export and Decrement Bid NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction exports and Decrement Bids will be offset in order from the lowest to the highest-priced transactions or bids.

III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)

III.F.2.3.3.1. Eligibility for Credit. All Market Participants that submit pool-scheduled External Transactions (import or export) are eligible for Real-Time External Transaction NCPC Credits, with the exception of External Transactions to wheel energy through the New England Control Area.

III.F.2.3.3.2. Eligible Quantity.

(a) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that either (i) did not clear in the Day-Ahead Energy Market, or (ii) cleared in the Day-Ahead

Energy Market and the price was subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction.

(b) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that cleared in the Day-Ahead Energy Market and the price was not subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction in excess of the cleared Day-Ahead scheduled transaction amount.

III.F.2.3.3.3. Hourly Offer. The hourly offer for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval offer, which is calculated by multiplying the eligible quantity by the offer price for the interval.

III.F.2.3.3.4. Hourly Revenue. The hourly revenue for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval revenue, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

III.F.2.3.3.5. Hourly Bid. The hourly bid for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval bid, which is calculated by multiplying the eligible quantity by the bid price for the interval.

III.F.2.3.3.6. Hourly Cost. The Real-Time cost for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval cost, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

III.F.2.3.3.7. Credit Calculation. A Real-Time External Transaction NCPC Credit for an External Transaction import for an hour is equal to any portion of the hourly offer in excess of the hourly revenue. A Real-Time External Transaction NCPC Credit for an External Transaction export for an hour is equal to any portion of the hourly cost in excess of the hourly bid.

III.F.2.3.4. [Reserved.]

III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits

III.F.2.3.5.1. Eligibility for Credit. A Resource that is dispatched as a Synchronous Condenser is eligible for Real-Time Synchronous Condensing NCPC Credits.

III.F.2.3.5.2. Condensing Offer Amount. The condensing offer amount for a Resource is equal to the number of hours that the Resource is dispatched as a Synchronous Condenser in an Operating Day multiplied by the hourly price to condense as specified in the Offer Data for the Resource. For a Resource committed from an offline state to provide synchronous condensing, the condensing offer amount includes the condensing start-up fee as specified in the Offer Data for the Resource. In the event an hourly price to condense or condensing start-up fee is not included in the Offer Data for the Resource for the hours that the Resource is dispatched as a Synchronous Condenser, the value for the parameter will be zero.

III.F.2.3.5.3. Credit Calculation. The Real-Time Synchronous Condensing NCPC Credit for a Resource for an Operating Day is equal to the condensing offer amount for that Operating Day.

III.F.2.3.6. Cancelled Start NCPC Credits

III.F.2.3.6.1. Eligibility for credit. A Pool-Scheduled Generator Asset or Demand Response Resource is eligible for a Cancelled Start NCPC Credit if the ISO cancels its commitment of the Pool-Schedule Resource before a Generator Asset is synchronized to the New England Transmission System, or before a Demand Response Resource has completed its Demand Response Resource Notification Time, except that a Market Participant is not eligible for a credit under the following conditions:

(a) The start is cancelled before the commencement of the Notification Time or the Demand Response Resource Notification Time;

(b) The Resource's Notification Time or Demand Response Resource Notification Time as reflected in the Effective Offer is equal to or greater than 24 hours;

(c) The Generator Asset is synchronized to the New England Transmission System for a Self-Schedule within the period of time equal to the lesser of its Minimum Down Time or 10 hours after receiving the ISO cancelled start order; or

(d) The Generator Asset fails to meet its scheduled synchronization time and the ISO cancelled start order is issued more than two hours after the Resource's scheduled synchronization time.

III.F.2.3.6.2. Credit Calculation. The Cancelled Start NCPC Credit for a Resource is equal to the Start-Up Fee or Interruption Cost reflected in the Effective Offer multiplied by the percentage of the Notification Time or Demand Response Resource Notification Time, as reflected in the Effective Offer, that the Resource completed prior to the ISO cancelled start order, where:

(a) The percentage of Notification Time or Demand Response Notification Time completed is equal to the number of minutes after the start of the Notification Time or Demand Response Notification Time the Resource was cancelled divided by the Notification Time or Demand Response Notification Time, and cannot exceed 100%.

III.F.2.3.7. Hourly Shortfall NCPC Credits

III.F.2.3.7.1. Eligibility for Credit. A Generator Asset, Demand Response Resource, or Binary Storage DARD that is pool-scheduled in the Day-Ahead Energy Market is eligible for Hourly Shortfall NCPC Credits for an hour if the ISO (1) cancels its commitment of a non-Fast Start Generator, a non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator; or (2) does not dispatch a Fast Start Generator, a Fast Start Demand Response Resource, a Binary Storage DARD, or a Flexible DNE Dispatchable Generator for the hour; and (3) either the Generator Asset or Binary Storage DARD is offline and available for operation and the Generator Asset associated with the DARD is not supplying electricity to the grid, or the Demand Response Resource has not been dispatched and is available for operation; except that (4) a Market Participant is not eligible for a credit under the following conditions:

(a) The Resource has been Postured for all or part of the hour;
(b) The Resource is a Limited Energy Resource that has been Postured during a prior hour in the Operating Day; or
(c) The Resource is an Intermittent Power Resource that is not a DNE Dispatchable Generator.

III.F.2.3.7.2. Settlement Period. For purposes of calculating Hourly Shortfall NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is eligible for an Hourly Shortfall NCPC Credit. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.

III.F.2.3.7.3. Eligible Quantity. The eligible quantity for each hour of the settlement period is:

(a) zero for a Fast Start Generator, a Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter, the Start-Up Fee and the No-Load Fee of the Supply Offer, or the total of the energy price parameter and the Interruption Cost of the Demand Reduction Offer, in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market for the hour is greater than the total of the corresponding energy price, Start-Up Fee, No Load Fee, and Interruption Cost parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;
   i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9(e), the Start-Up Fee, No-Load Fee and energy at the

Economic Minimum Limit are equal to $0, and (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9(f), the Start-Up Fee and No-Load Fee are equal to $0 and the energy at the requested dispatch level is the Energy Price Floor.

(b) zero for a Binary Storage DARD in the event the energy price parameter in the Demand Bid in the Real-Time Energy Market for the consumption cleared in the Day-Ahead Energy Market for the hour is less than the energy price parameter in the Demand Bid in the Day-Ahead Energy Market for the hour.

i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9 (e), then the energy price at the Minimum Consumption Limit is equal to the Demand Bid Cap, and; (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9 (f), then the energy price at the requested dispatch level for Binary Storage DARDs is the Demand Bid Cap.

(c) the Day-Ahead Economic Minimum Limit or Minimum Reduction for a non-Fast Start Generator, non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter of the Supply Offer or Demand Reduction Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market above the Day-Ahead Economic Minimum Limit or Day-Ahead Minimum Reduction for an hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

and if neither (a) nor (b) nor (c) applies, then;

(d) the minimum of (i) the amount of energy cleared in the Day-Ahead Energy Market for an hour and (ii) the Resource's Economic Maximum Limit, Maximum Reduction, or a Limited Energy Resource limit imposed for the hour in the Real-Time Energy Market.

III.F.2.3.7.4. Credit Calculation (for non-Fast Start Generators, non-Fast Start Demand Response Resources, and non-Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC

Credit for a Resource, other than a Fast Start Generator, a Fast Start Demand Response Resource, a Binary Storage DARD, or a Flexible DNE Dispatchable Generator, adjusted as described in III.F.1(h), is equal to:

(a) the greater of (i) zero and (ii) the total of (the Real-Time Price minus the Day-Ahead Price for an hour, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, multiplied by the Day-Ahead Economic Minimum Limit for the hour or the Day-Ahead Minimum Reduction for the hour) for all hours of the settlement period,

plus

(b) for each hour of the settlement period, for Generator Assets, the greater of (i) zero and (ii) the product of (1) the Real-Time Price minus the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, for an hour and (2) the eligible quantity minus the Day-Ahead Economic Minimum Limit for the hour; or, for Demand Response Resources, the greater of (i) zero and (ii) the product of (1) the Real Time Price minus the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, for an hour and (2) the eligible quantity minus the Day-Ahead Minimum Reduction for the hour.

III.F.2.3.7.5. Credit Calculation (for Fast Start Generators, Fast Start Demand Response Resources and Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC Credit for a Fast Start Generator, Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and (ii) the Real-Time Price minus the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, for an hour, multiplied by the eligible quantity for the hour, adjusted as described in III.F.1(h).

III.F.2.3.7.6 Credit Calculation (for Binary Storage DARDs). The Hourly Shortfall NCPC Credit for a Binary Storage DARD is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the Day-Ahead Locational Marginal Price minus the Real-Time Price for an hour, multiplied by the eligible quantity for the hour.

III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability

III.F.2.3.8.1. Eligibility for Credit. A Limited Energy Resource is eligible for real-time posturing NCPC credits for any Operating Day during which the Generator Asset has been Postured, when a request to minimize the as-bid production costs of the Generator Asset has been submitted. For purposes of calculating real-time posturing NCPC credits, the Generator Asset is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Generator Asset was Postured, and if not the Generator Asset is treated as a non-Fast Start Generator. If the Generator Asset is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

III.F.2.3.8.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits for Limited Energy Resources, a settlement period is the period of one or more contiguous hours from the initiation of Posturing through the end of the Operating Day.

III.F.2.3.8.3 Resources Sharing a Single Fuel Source. When Limited Energy Resources that share a fuel source are Postured, for purposes of calculating real-time posturing NCPC credits the energy available to the Postured Generator Assets will be allocated among the Postured Generator Assets sharing the fuel source as indicated by estimates of available energy provided by the Lead Market Participant for each Generator Asset prior to Posturing.

III.F.2.3.8.4. Estimated Replacement Cost of Energy. The estimated replacement cost of energy is (i) the average of the Day-Ahead Locational Marginal Prices for hours ending 3 through 5 in the subsequent Operating Day for a Generator Asset that is part of an Electric Storage Facility, or (ii) the product of the oil index price multiplied by the oil-fired generator proxy heat rate for fuel oil-fired generating units, or (iii) zero for all other Generator Assets.

For fuel oil-fired generators, the oil index price is the ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation, and the oil-fired generator proxy heat rate is the average of the heat rate at Economic Min and the heat rate at Economic Max, where the heat rate at Economic Min is, for a Generator Asset, the average hourly energy price parameter of the Supply Offer at the Generator Asset's Economic Minimum Limit at the time of the Posturing decision divided by the oil index price, and the heat rate at Economic Max is, for a Generator Asset, the average hourly energy price parameter of the Supply Offer at the Generator Asset's Economic Maximum Limit at the time of the Posturing decision divided by the oil index price.

III.F.2.3.8.5. Estimated Revenue. The estimated revenue for a Generator Asset is the optimized energy output multiplied by the Real-Time Price for all hours in the settlement period. The optimized energy output is estimated for each hour by allocating the Postured energy to hours that the Generator Asset would have operated had it not been Postured based on Real-Time Prices in the Operating Day, subject to the following conditions:

(a) the optimized energy output determination will take account of the Generator Asset's Economic Minimum Limit, and Economic Maximum Limit.

(b) the optimized energy output determination will take account of the estimated avoided cost of replacing energy that is not allocated to any hour and remains available at the end of the Operating Day.

(c) for non-Fast Start Generators, the optimized energy output is calculated for the contiguous hours from the time the Generator Asset is Postured until the available energy is depleted.

III.F.2.3.8.6. Estimated Avoided Replacement Cost. The estimated avoided replacement cost for an Operating Day is the remaining energy that would have been available at the end of the Operating Day had the Generator Asset operated in accordance with the optimized energy output determination in Section III.F.2.3.8.5, plus any increase in the remaining energy resulting from replenishment during the Operating Day after the Generator Asset is Postured, multiplied by the estimated replacement cost of energy.

III.F.2.3.8.7. Actual Revenue. The actual revenue for a Generator Asset is the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the settlement period.

III.F.2.3.8.8. Actual Avoided Replacement Cost. The actual avoided replacement cost for an Operating Day is the actual remaining energy at the end of the Operating Day multiplied by the estimated replacement cost of energy.

III.F.2.3.8.9. Credit Calculation. The real-time posturing NCPC credit for Limited Energy Resources is equal to the greater of (i) zero and (ii) the estimated revenue plus the estimated avoided replacement cost, minus the actual revenue plus the actual avoided replacement cost.

III.F.2.3.9. Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured for Reliability and for Demand Response Resources Postured for Reliability

III.F.2.3.9.1. Eligibility for Credit. Generator Assets (other than Limited Energy Resources) and Demand Response Resources are eligible for real-time posturing NCPC credits for the hours during which the Resource has been Postured.

III.F.2.3.9.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits, a settlement period is an hour during which the Generator Asset or Demand Response Resource is Postured.

III.F.2.3.9.3. Offer Used for Estimated Hourly Revenue and Cost.

(a) For a Generator Asset, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:

 (i) Energy Price: the higher of the energy price parameter specified in (1) the Supply Offer for the hour at the time the ISO Postures the Generator Asset, or (2) the Supply Offer for the hour at the start of the hour;

 (ii) Start-Up Fee and No Load Fee: for Generator Assets Postured offline, the Start-Up Fee and No-Load Fee specified in the Supply Offer for the hour at the time the Generator Asset is Postured;

 (iii) for Generator Assets Postured to remain online but reduce output, the Start-Up Fee and No-Load Fee are calculated pursuant to Section III.F.2.2.2.3.

(b) For a Demand Response Resource, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:

 (i) Energy Price: the higher of the energy price parameter specified in (1) the Demand Reduction Offer for the hour at the time the ISO Postures the Resource, or (2) the Demand Reduction Offer for the hour at the start of the hour;

 (ii) Interruption Cost: for a Demand Response Resource Postured to a demand reduction of zero MW, the Interruption Cost specified in the Demand Reduction Offer for the hour at the time the Demand Response Resource is Postured; for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MW, the Interruption Cost is calculated pursuant to Section III.F.2.2.2.3.

III.F.2.3.9.4. Estimated Hourly Revenue.

(a) The estimated hourly revenue for a Generator Asset is the optimized energy output multiplied by the Real-Time Price for the hour. The optimized energy output is estimated for each hour by determining where the Generator Asset would have operated had it not been Postured based on Real-Time Prices. The optimized energy output determination will take account of the energy price parameter of the Supply Offer and the Generator Asset's Economic Minimum Limit and Economic Maximum Limit.

(b) The estimated hourly revenue for a Demand Response Resource is the optimized demand reduction multiplied by the Real-Time Price for the hour, where:

(i) The optimized demand reduction is estimated for each hour by determining where the Demand Response Resource would have operated had it not been Postured based on Real-Time Prices. The optimized demand reduction determination will take account of the energy price parameter of the Demand Reduction Offer and the Demand Response Resource's Minimum Reduction and Maximum Reduction.

III.F.2.3.9.5. Estimated Hourly Cost.

(a) The estimated hourly cost for a Generator Asset is the energy price parameter of the Supply Offer for the optimized energy output for the hour, plus the Start-Up Fee and the No-Load Fee, subject to the following conditions:

(i) For a Fast Start Generator Postured offline, the Start-Up Fee is included in each hour's cost and is not subject to apportionment;

(ii) For a non-Fast Start Generator Postured offline, the Start-Up Fee is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.

(b) The estimated hourly cost for a Demand Response Resource is the energy price parameter of the Demand Reduction Offer for the optimized demand reduction for the hour (where optimized demand reduction is determined pursuant to Section III.F.2.3.9.4(b)), plus the Interruption Cost, subject to the following conditions:

(i) For a Fast Start Demand Response Resource Postured to a demand reduction level of zero MW, the Interruption Cost is included in each hour's cost and is not subject to apportionment;

(ii) For a non-Fast Start Demand Response Resource Postured to a demand reduction of greater than zero MW, the Interruption Cost is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.

(c) A Generator Asset is treated as a Fast Start Generator and a Demand Response Resource is treated as a Fast Start Demand Response Resource for purposes of determining the estimated hourly cost only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator or non-Fast Start Demand Response Resource. If at the time the Resource is Postured the Generator Asset is offline, or the Demand Response Resource has not been dispatched, then its designation as a Fast Start Generator or Fast Start Demand Response Resource is determined as of the time of the Posturing decision.

III.F.2.3.9.6. Actual Hourly Revenue. The actual hourly revenue for a Generator Asset or a Demand Response Resource is the sum of the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the hour.

III.F.2.3.9.7. Actual Hourly Cost.

(a) The actual hourly cost for a Generator Asset Postured to remain online but reduce output is the sum of the interval cost, which is the energy price parameter of the Supply Offer for the Metered Quantity For Settlement for the interval, plus the Start-Up Fee and No-Load Fee calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Generator Asset Postured offline is zero.

(b) The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MW is the sum of the interval cost, which is the energy price parameter of the Demand Reduction Offer for the Metered Quantity For Settlement for the interval, plus the Interruption Cost calculated pursuant to pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to zero MW is zero.

III.F.2.3.9.8. Credit Calculation. The real-time posturing NCPC credit for a Generator Asset (other than a Limited Energy Resource) or a Demand Response Resource is equal to the greater of (i) zero and (ii) the estimated hourly revenue minus the estimated hourly cost, minus the actual hourly revenue minus actual hourly cost, adjusted as described in III.F.1(h).

III.F.2.3.10. Rapid Response Pricing Opportunity Cost NCPC Credits Resulting from Commitment of Rapid Response Pricing Assets

III.F.2.3.10.1. Eligibility for Credit. During any five-minute pricing interval in which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, any Resource that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Rapid Response Pricing Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Resource is non-dispatchable; the Resource has been Postured or has provided Regulation during the interval; if the Resource is a Settlement Only Resource, or if the Resource is an External Resource or External Transaction.

III.F.2.3.10.2. Economic Net Revenue or Economic Net Benefit.

(a) The economic net revenue for a Generator Asset or Demand Response Resource during the pricing interval is the Resource's optimized feasible energy quantity multiplied by the Real-Time Price, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

(b) The economic net benefit for a Dispatchable Asset Related Demand during the pricing interval is the Resource's energy price parameter for its optimized feasible energy quantity as reflected in its Demand Bid, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the optimized feasible energy quantity multiplied by the Real-Time Price.

(c) The optimized feasible energy and reserve quantities are determined consistent with the Resource's offer or bid parameters, and are the energy and reserve quantities that maximize the Resource's economic net revenue or economic net benefit for the pricing interval, without changing the Resource's commitment status.

III.F.2.3.10.3. Actual Net Revenue or Actual Net Benefit.

(a) Except as provided in Section III.F.2.3.10.3(b), the actual net revenue for a Generator Asset or Demand Response Resource is the greater of: (i) the actual energy quantity supplied during the pricing interval multiplied by the Real-Time Price, plus the actual reserve quantity supplied during the pricing interval multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities; and (ii) the dispatched energy quantity multiplied by the Real-Time Price, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

(b) The actual net revenue for a Generator Asset associated with an ATRR that has provided Regulation during the interval is equal to the dispatched energy quantity multiplied by the Real-Time Price, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

(c) Except as provided in Section III.F.2.3.10.3(d), the actual net benefit for a Dispatchable Asset Related Demand is the greater of: (i) the energy price parameter for the actual energy quantity consumed as reflected in the Demand Bid, plus the actual reserve quantity supplied multiplied by the Real-Time Reserve Clearing Price, minus the actual energy quantity consumed multiplied by the Real-Time Price, and (ii) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.

(d) The actual net revenue for a DARD associated with an ATRR that has provided Regulation during the interval is equal to the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.

III.F.2.3.10.4. Credit Calculation. The Rapid Response Pricing Opportunity Cost NCPC Credit for a Resource is equal to the greater of: (i) zero; and (ii) the Resource's economic net revenue or economic net benefit for the interval less its actual net revenue or actual net benefit for the pricing interval.

The Rapid Response Pricing Opportunity Cost NCPC Credit for a Resource for an interval shall be reduced by the amount of any Real-Time Dispatch NCPC Credits for which the Resource is eligible for that interval, but shall be no less than zero.

III.F.2.4. Apportionment of NCPC Credits. For purposes of this Section III.F.2.4, any values previously established at the five-minute level shall be aggregated to create hourly values.

Each Day-Ahead Market NCPC Credit calculated pursuant to III.F.2.1.6 is apportioned to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue for all hours in the settlement period.

Each Real-Time Commitment NCPC Credit is apportioned as follows: (i) for the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the portion of the Commitment Period, and (ii) for all remaining intervals of the settlement period, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the period.

Each Hourly Shortfall NCPC Credit for a non-Fast Start Generator, a non-Fast Start Demand Response Resource or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator for energy cleared in the Day-Ahead Market at the Resource's Economic Minimum Limit or Minimum Reduction is apportioned to the hours in which the Real-Time Price exceeds the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, for all hours in the settlement period.

The following NCPC credits are assigned to the hours for which the credit was calculated:

- Day-Ahead Market NCPC Credits calculated pursuant to Section III.F.2.1.7.

- Real-Time Dispatch Lost Opportunity Cost NCPC Credits,
- Real-Time Dispatch NCPC Credits for all Resources,
- Day-Ahead External Transaction Import and Increment Offer NCPC Credits,
- Day-Ahead External Transaction Export and Decrement Bid NCPC Credits,
- Real-Time External Transaction NCPC Credits,
- Hourly Shortfall NCPC Credits for Fast Start Generators, Fast Start Demand Response Resources, Binary Storage DARDs and Flexible DNE Dispatchable Generators,
- Hourly Shortfall NCPC Credits for non-Fast Start Generators, non-Fast Start Demand Response Resources, and DNE Dispatchable Generators that are not Flexible DNE Dispatchable Generators for energy cleared in the Day-Ahead Energy Market above the Resource's Economic Minimum Limit or Minimum Reduction, and
- Rapid Response Pricing Opportunity Cost NCPC Credits as described in Section III.F.2.3.10.

III.F.2.5. NCPC Credit Designation for Purposes of NCPC Cost Allocation. Each hourly credit for Day-Ahead Market NCPC Credits, Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, Day-Ahead External Transaction Import and Increment Offer NCPC Credits, Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, Real-Time External Transaction NCPC Credits, Hourly Shortfall NCPC Credits, and Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured For Reliability and Demand Response Resources Postured For Reliability, and each daily credit for Real-Time Synchronous Condensing NCPC Credits, Cancelled Start NCPC Credits, Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability, and Rapid Response Pricing Opportunity Cost NCPC Credit is designated as first contingency, second contingency, voltage (VAR), distribution (SCR), ISO initiated audits and Minimum Generation Emergency consistent with the reason provided by the ISO when issuing a Dispatch Instruction for the Resource. If there is more than one reason provided by the ISO when issuing the Dispatch Instruction, the NCPC Credits are divided equally for purposes of the above designations. With the exception of Day-Ahead External

Transaction Import and Increment Offer NCPC Credits and Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, the hourly credits are summed to determine the total credits for each NCPC Charge category for a day.

III.F.3. Charges for NCPC

III.F.3.1. Cost Allocation.

III.F.3.1.1 Day-Ahead Market NCPC Cost Allocation. NCPC costs for the Day-Ahead Energy Market are allocated and charged as follows:

(a) The total NCPC cost for the Day-Ahead Energy Market associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Day-Ahead Energy Market for resources designated as Special Constraint Resources in the Day-Ahead Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total NCPC cost for the Day-Ahead Energy Market for resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

(d) For each External Node, the total NCPC cost for Day-Ahead External Transaction Import and Increment Offer NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Load Obligations at the External Node for the hour.

(e) For each External Node, the total Day-Ahead External Transaction Export and Decrement Bid NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Generation Obligations at the External Node for the hour.

(f) All remaining NCPC costs for the Day-Ahead Market (except the NCPC costs for Storage DARDs) are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub).

(g) All remaining NCPC costs for the Day-Ahead Energy Market associated with Storage DARDs are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub) excluding Day-Ahead Load Obligations associated with Storage DARDs.

III.F.3.1.2. Real-Time Energy Market NCPC Cost Allocation. NCPC costs for the Real-Time Energy Market are allocated and charged as follows, subject to the conditions in Section III.F.3.1.3:

(a) The total NCPC cost for the Real-Time Energy Market associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are allocated and charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Real-Time Energy Market for resources designated as Special Constraint Resources in the Real-Time Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total ISO initiated audit NCPC cost for resources performing an ISO initiated audit is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.

(d) The total NCPC cost for resources being Postured in the Real-Time Energy Market is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.

(e) The total NCPC cost for Rapid Response Pricing Opportunity Cost NCPC Credit during pricing intervals in which one or more Rapid Response Pricing Asset is committed in the Real-Time Energy Market (and not Self-Scheduled) is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.

(f) The total NCPC cost for the Real-Time Energy Market for resources identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

(g) Total Minimum Generation Emergency Credits within a Reliability Region are allocated and charged hourly to Market Participants based on each Market Participant's pro rata share of Real-Time Generation Obligations, and positive Real-Time Demand Reduction Obligations, excluding that portion of a Market Participant's Real-Time Generation Obligation and Real-Time Demand Reduction Obligation within a Reliability Region that is eligible for a Real-Time Dispatch NCPC Credit pursuant to Section III.F.2.2.3 during a Minimum Generation Emergency.

(h) The total NCPC cost for Real-Time Dispatch Lost Opportunity Cost NCPC Credits is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.

(i) All remaining NCPC costs for the Real-Time Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of the absolute values of a Market Participant's (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day (excluding certain positive Real-Time Load Obligation Deviations as described in Section III.F.3.1.3(d)); (ii) generation deviations for Pool-Scheduled Resources not following Dispatch Instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following Dispatch Instructions, and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following Dispatch Instructions, including External Resources, in MWhs during the Operating Day; (iii) demand reduction deviations for Pool-Scheduled Demand Response Resources not following Dispatch Instructions; and (iv) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day. The Real-Time deviations calculation is specified in greater detail in Section III.F.3.2.

III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation.

(a) If a Generator Asset has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.

(b) If a Demand Response Resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the resource should not be dispatched in order to avoid a Minimum Generation Emergency, the Market Participant will be responsible for all Real-Time Demand Reduction Obligation Deviation charges, but will not incur related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.

(c) Any difference between the actual consumption (Real-Time Load Obligation) of a DARD and the DARD's Demand Bids that clear in the Day-Ahead Energy Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation for the purpose of allocating costs for Real-Time Energy Market NCPC Credits.

(d) In any hour during which a Capacity Scarcity Condition occurs or ISO New England Operating Procedure No. 4 or ISO New England Operating Procedure No. 7 are implemented, any NCPC Charges that would have been allocated pursuant to Section III.F.3.2 to net positive Real-Time Load Obligation Deviations in an affected Load Zone (and related portion of adjacent External Nodes) are instead allocated and charged to Market Participants based on their pro rata share of the sum of their Real-Time Load Obligation (excluding Real-Time Load Obligations associated with a Postured Dispatchable Asset Related Demand Resource) in all the affected Load Zones and (and related portion of adjacent External Nodes) during the affected hour(s). For purposes of this calculation, the ISO shall apportion any Real-Time Load Obligations and Real-Time Load Obligation Deviations at an External Node equally among the Load Zones to which the External Node is interconnected.

III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits.

Each Market Participant's pro-rata share of the Real-Time deviations for Real-Time Energy Market NCPC Credits is the following:

(a) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead Energy Market MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead Energy Market MWh or less than or equal to 5 MWh, then deviation = 0.

(b) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead Energy Market MWh) or (actual metered output – Real-Time Economic Minimum Limit) or (Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead Energy Market MWh or less than or equal to 5 MWh, then deviation = 0.

(c) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

plus,

(d) for each Pool-Scheduled Generator Asset and Continuous Storage Generator Asset:

(i) If the Generator Asset is not following Dispatch Instructions, has cleared the Day-Ahead Energy Market, has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output − Desired Dispatch Point) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Generator Asset is not following Dispatch Instructions, has cleared the Day-Ahead Energy Market, has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – cleared Day-Ahead MWh) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead Energy Market MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(e) for each Pool-Scheduled Demand Response Resource:

(i) If the Demand Response Resource is being dispatched, is not following Dispatch Instructions, has cleared in the Day-Ahead Energy Market, and has not been ordered to stop reducing demand for reliability purposes: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction − Desired Dispatch Point) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Demand Response Resource is unavailable and has cleared in the Day-Ahead Energy Market: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction – cleared Day-Ahead MWh) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead Energy Market MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation,

where

(i) each Market Participant's Real-Time Load Obligation Deviation for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub), and

(ii) for purposes of calculating a Participant's Real-Time Load Obligation Deviation under this sub-section (e), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and

(iii) External Transaction sales curtailed by the ISO are omitted from this calculation.

plus,

(g) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation,

where

(i) each Market Participant's Real-Time Generation Obligation Deviation at External Nodes for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes, and

(ii) for purposes of calculating a Participant's Real-Time Generation Obligation Deviation under this sub-section (f), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and

(iii) External Transaction purchases curtailed by the ISO are omitted from this calculation.

plus,

(h) the absolute value of the total over all Locations of the Market Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

III.F.3.3 Local Second Contingency Protection Resource NCPC Charges.

Each Market Participant's pro-rata share of the cost for Day-Ahead Market NCPC Credits and Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection is based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region, excluding Real-Time Load Obligations associated with Storage DARDs subject to the following conditions:

(a) The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating a Market Participant's pro-rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

(b) For hours in which there is an NCPC cost for a resource providing Local Second Contingency Protection and ISO is selling Emergency Energy to an adjacent Control Area, the scheduled amount of Emergency Energy at the applicable External Node will be included in the calculation of a Market Participant's pro rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection as if the Emergency Energy sale were a Real-Time Load Obligation within each affected Reliability Region. The pro rata share calculated for the Emergency Energy transaction shall be included in the charges under an agreement for purchase and sale of Emergency Energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency Energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

External Node Common Name	Associated Transmission Facilities	Reliability Region(s)	Allocator
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390/3016) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-7 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line) Alps – Berkshire Line (393Line) Pleasant Valley – Long Mountain Line (398 Line)	Vermont, Vermont Vermont West Central Massachusetts West Central Massachusetts Connecticut	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
NY NNC External Node	Northport-Norwalk Harbor (601,602 and 603 Lines)	Connecticut	100% to Connecticut
NY CSC External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(c) For each month, the ISO performs an evaluation of total Local Second Contingency Protection Resource NCPC Charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph c, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency Energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Storage DARD.

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ > .06 X Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$

Condition 2 – is the Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ > 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\%}$ $_{\text{(Reliability Region)}}$

Where:

Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$, a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ is triggered.

(ii) Determination of the portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated –

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated = Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ X Min (Condition 1 Rate $_{\text{(Reliability Region, month)}}$, Condition 2 Rate $_{\text{(Reliability Region, month)}}$)

Where:

Condition 1 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus .06 times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Condition 2 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\% (Reliability Region)}}$ times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

(iii) Determination of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

(Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ / Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

(Regional Network Load $_{\text{(Transmission Customer, Reliability Region, month)}}$ / Regional Network Load $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Regional Network Load $_{(\text{Reliability Region, month})}$ equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load $_{(\text{Customer, Reliability Region, month})}$ equals:
The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

III.F.4. NCPC Reporting

III.F.4.1. Zonal NCPC Report. Beginning January 2019, for each month, no later than 20 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating the aggregate dollar amount of NCPC Credits by category paid to the resources located in each Load Zone for each day during that month.

III.F.4.2. Resource-Specific NCPC Report. Beginning January 2019, for each month, no later than 90 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating the name of each resource that received NCPC Credits for that month and the total dollar amount of NCPC Credits that each of those resources received for that month.

III.F.4.3. Operator-Initiated Commitment Report. Beginning January 2019, for each month, no later than 30 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating each resource commitment made during that month after the Day-Ahead Energy Market for a reason other than minimizing the total production costs of serving load. For each such commitment, the report shall include the start time, the Economic

Maximum Limit or Maximum Reduction of the committed resource, the Load Zone in which the committed resource is located, and the reason for the commitment.