# Overview of New England's Wholesale Electricity Markets and Market Oversight

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# Introduction

ISO New England (ISO) is responsible for overseeing and administering New England's competitive wholesale electricity markets. These markets work together to ensure the constant availability of electricity from the bulk power grid for the region's 6.5 million households and businesses and 14 million people. In 2012, approximately 500 market participants participated in one or more markets with a combined value of $6.1 billion (for electric energy, capacity, forward reserves, regulation, and daily reliability payments). Participants also have the opportunity to hedge against the costs associated with transmission congestion through Financial Transmission Rights (FTRs) and the associated auction revenue distributions. The wholesale electricity markets and market products in New England are as follows:

- **Day-Ahead Energy Market—**allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time; facilitates electric energy trading.
- **Real-Time Energy Market—**coordinates the dispatch of generation and demand resources to meet the demand for electricity and to meet reserve requirements.[1]
- **Forward Capacity Market (FCM)—**ensures the sufficiency of installed capacity, which includes demand resources, to meet the future demand for electricity.
- **Financial Transmission Rights (FTRs)—**allow participants to hedge against the economic impacts associated with transmission congestion and provide a financial instrument to arbitrage differences between expected and actual day-ahead congestion.
- **Ancillary services**
    - **Regulation Market—**compensates participants whose resources are controlled by the ISO using automated signals to increase or decrease output moment by moment to balance the variations in instantaneous demand and the system frequency; demand varies second to second, and the system frequency must be kept at a constant rate.
    - **Forward Reserve Market (FRM)—**compensates generators for the availability of their unloaded operating capacity that can be converted into electric energy within 10 or 30 minutes when needed to meet system contingencies, such as unexpected outages.[2]
    - **Real-time reserve pricing—**is the ISO's mechanism to implement *scarcity pricing*, which compensates participants with on-line and fast-start generators for the increased value of their electric energy when the system or portions of the system are short of reserves.[3] It also provides efficient price signals when redispatch is needed to provide additional reserves to meet requirements.
    - **Voltage support—**compensates resources for maintaining voltage-control capability, which allows system operators to maintain transmission voltages within acceptable limits.

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[1] *Demand resources* are installed measures (i.e., products, equipment, systems, services, practices, and strategies) that result in additional and verifiable reductions in end-use demand on the electricity network during specific performance hours.

[2] *Unloaded* operating capacity is operational capacity that is not generating electric energy but that could convert to generating energy. A *contingency* is the sudden loss of a generation or transmission resource. A *first contingency* (N-1) is when the first power element (facility) with the largest impact on system reliability is lost. A *second contingency* (N-1-1) takes place after a first contingency has occurred and is the loss of the facility that at that point would have the largest impact on the system.

[3] *Fast-start resources* are resources able to respond quickly to system contingencies (i.e., the sudden loss of a generation or transmission resource.

- **Other services and products**—The ISO procures and compensates participants for other services and products as required by the ISO's *Open Access Transmission Tariff* (OATT).[4]

The ISO relies on two independent market monitors—the Internal Market Monitor (IMM) and the External Market Monitor (EMM). Every year, the ISO's market monitors review and report on market results and offer insights into the markets' competitiveness and effectiveness, as well as areas of market design and operation that need enhancement or improvement.

This report describes the key features of each of the wholesale energy markets the ISO oversees and administers. It also summarizes the market oversight, analysis, and mitigation activities for the New England markets. Key terms are italicized and defined within the text.

# Electric Energy Markets

The primary objective of the electricity markets operated by ISO New England is to ensure a reliable and economic supply of electricity to the high-voltage power grid. The markets include a Day-Ahead Energy Market and a Real-Time Energy Market. In what is termed a *multisettlement system*, each of these markets produces a separate but related financial settlement.

The Day-Ahead Energy Market produces financially binding schedules for the sale and purchase of electricity one day before the operating day. However, supply or demand for the operating day can change for a variety of reasons, including generator reoffers of their supply into the market, real-time hourly *self-schedules* (i.e., generators' choosing to be on line and operating at a fixed level of output regardless of the price of electric energy), transmission or generation outages, and unexpected real-time system conditions. Physically, real-time operations balance instantaneous changes in supply and demand and ensure that adequate reserves are available to operate the transmission system within its limits. Financially, the Real-Time Energy Market settles the differences between the day-ahead scheduled amounts of load and generation and the actual real-time load and generation. Participants either pay or are paid the real-time *locational marginal price* (LMP) (see below) for the amount of load or generation in megawatt-hours (MWh) that deviates from their day-ahead schedule.

This section summarizes the key features of the ISO's Day-Ahead and Real Time Energy Markets, including locational marginal pricing; the factors influencing electric energy supply offers, demand bids, and LMPs; and virtual and real-time trading.

## Locational Marginal Prices and Pricing Locations

Locational marginal pricing is a way for wholesale electric energy prices to efficiently reflect the value of electric energy at different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. In New England, wholesale electricity prices are identified at 900 pricing points (i.e., *pnodes*) on the bulk power grid. If the system were entirely unconstrained and had no losses, all LMPs would be the same, reflecting only the cost of serving the next increment of load. The generator with the lowest-cost energy offer available would serve that incremental megawatt of load, and electric energy from that generator would be able to flow to any node on the transmission system. LMPs differ generally among locations because transmission and reserve constraints prevent the next-cheapest

[4] The ISO operates under several FERC tariffs, including the *ISO New England Transmission, Markets, and Services Tariff* (ISO tariff) (2013), of which Section II is the *Open Access Transmission Tariff* (OATT) and Section IV is the *Self-Funding Tariff*. These documents are available at http://www.iso-ne.com/regulatory/tariff/index.html, http://www.iso-ne.com/regulatory/tariff/sect_2/index.html, and http://www.iso-ne.com/regulatory/tariff/sect_4/index.html.

megawatt (MW) of electric energy from reaching all locations of the grid. Even during periods when the cheapest megawatt can reach all locations, the marginal cost of physical losses will result in different LMPs across the system.

New England has five types of pnodes: one type is an external proxy node interface with neighboring balancing authority areas, and four types are internal to the New England system.[5] The internal pnodes include individual generator-unit nodes, load nodes, *load zones* (i.e., aggregations of load pnodes within a specific area), and the Hub. The *Hub* is a collection of locations with a load-weighted price intended to represent an uncongested price for electric energy, facilitate trading, and enhance transparency and liquidity in the marketplace. New England is divided into the following eight load zones: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA). Generators are paid the real-time LMP for electric energy at their respective nodes, and participants serving demand pay the price at their respective load zones.[6] The load-zone price is a load-weighted average price of the load-node prices in that zone.

*Import-constrained load zones* are areas within New England that must use more expensive generators than the rest of the system because local, inexpensive generation or transmission-import capability is insufficient to meet both local demand and reserve requirements. *Export-constrained load zones* are areas within New England where the available resources, after serving local load, exceed the areas' transmission capability to export excess electric energy.

## Electric Energy Supply Offers and Demand Bids

Supply offers and demand bids determine the LMPs. Production costs and supplier operating characteristics influence generator supply offers. For most electricity generators, the cost of fuel is the largest variable production cost, and as fuel costs change, the prices at which generators submit offers in the marketplace change correspondingly. Because fuel prices alone account for a large portion of electricity prices, as fuel prices change year to year, electricity prices change accordingly. The demand bids for electric energy reflect a participant's load-serving requirements and accompanying uncertainty, tolerance for risk, and expectations about congestion on the system caused by transmission constraints. The market-clearing process for the Day-Ahead Energy Market calculates and publishes LMPs at the various pnodes, accounting for supply offers, external transaction offers, virtual (financial) offers and bids, and day-ahead demand bids. The market-clearing process for the Real-Time Energy Market is based on supply offers, real-time load, and offers and bids to sell (import) or buy (export) energy over the external interfaces.

### Actual and Virtual Trading in the Day-Ahead Energy Market

The intersection of the supply and demand curves as offered and bid, along with transmission constraints and other system conditions, determines the Day-Ahead Energy Market price at each node and results in the binding financial schedules and commitment orders (refer to Figure 1). Market participants that have *real-time load obligations* (RTLOs) (i.e., they are serving load) may submit demand bids in the Day-Ahead Energy Market. Participants may bid *fixed demand* (i.e., they will buy at any price) and *price-sensitive*

[5] A *balancing authority area* is a group of generation, transmission, and loads within the metered boundaries of the entity (*balancing authority*) that maintains the load-resource balance within the area.

[6] *Market Rule 1* (http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_1-12.pdf), which is Section III of the ISO tariff, contains provisions that allow participants that meet certain requirements to request nodal pricing for load. However, the number of participants that have exercised this option and the quantity of load these participants serve is very small relative to the zonal load levels.

*demand* (i.e., they will buy up to a certain price) at their load zone (or pnode, for some participants that meet certain requirements). Generating units may submit three-part supply offers for their output at the pricing node specific to their location, including start-up, no-load, and incremental energy offers. *Start-up offers* reflect the costs associated with bringing a unit from an off-line state to the point of synchronizing with the grid. *No-load offers* reflect the hourly cost of operating that does not depend on the megawatt level of output. *Incremental energy offers* represent the willingness of participants to operate a resource at higher output levels for higher compensation. The incremental energy offers produce the upward sloping supply curve that is used to calculate the LMP. Market participants have the incentive to submit offers for start-up, no-load, and incremental energy consistent with their true costs to maximize the chance they will be running at profitable levels.

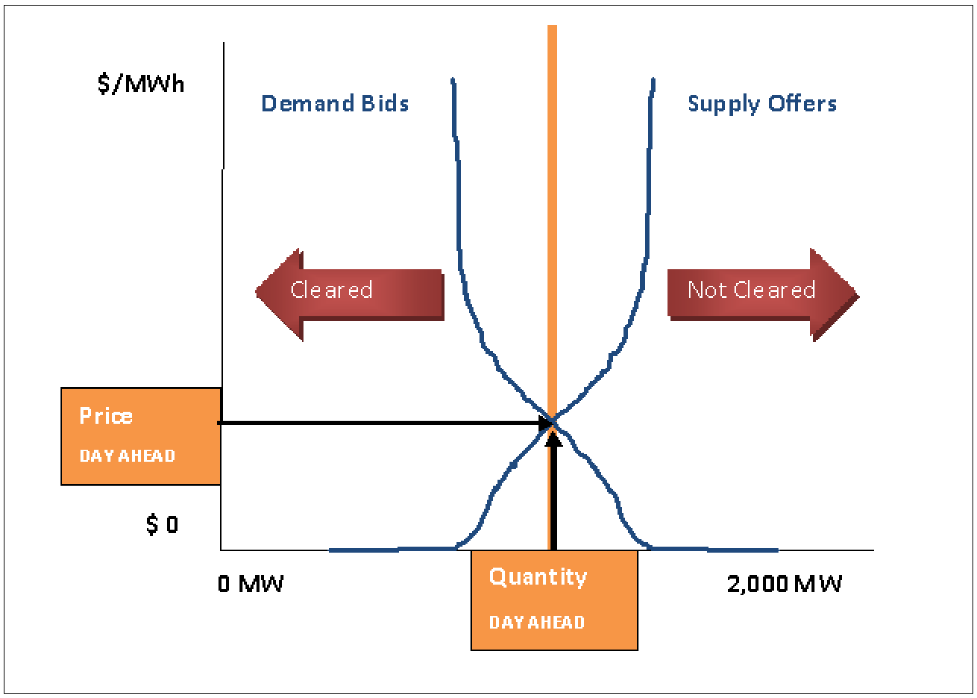


**Figure 1**: **Intersection of supply and demand curves indicating the clearing price.**

For each megawatt of virtual supply that clears in the Day-Ahead Energy Market, the participant receives the day-ahead LMP and has a financial obligation to pay the real-time LMP at the same location for megawatts not produced in real-time (i.e., for a "deviation"). For each megawatt of cleared virtual demand, the participant pays the day-ahead LMP and receives the real-time LMP at that location. That is, an accepted virtual supply offer in the Day-Ahead Energy Market is offset by a "purchase" in the Real-Time Energy Market, and a cleared virtual demand bid in the Day-Ahead Energy Market is offset by a "sale" in the Real-Time Energy Market. While these transactions affect the day-ahead prices, they do not represent physical supply or withdrawal of energy in real time. The difference between the day-ahead and real-time LMPs at the location at which the participant's offer or bid clears, plus all applicable transaction costs, including daily reliability costs (see section below), determine the financial outcome for a particular participant.

Any participant that satisfies the financial-assurance requirements detailed in the market rules also may bid price-sensitive virtual demand at any pricing node on the system in the Day-Ahead Energy Market. Participants also may offer virtual supply. Virtual trading enables market participants that are not generator owners or load-serving entities (LSEs) to participate in the Day-Ahead Energy Market by establishing virtual (or financial) positions. It also allows more participation in the day-ahead price-setting process, allows participants to manage risk in a multisettlement environment, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets.

Demand bids and virtual demand bids both can be used to hedge the difference between day-ahead and real-time prices. Demand bids are well suited to hedge RTLOs, and virtual demand bids can be used to arbitrage expected differences between day-ahead and real-time prices at a node or to hedge a nodal load.

## Real-Time Market Supply and Demand and Generator Commitment

The Real-Time Energy Market is a physical delivery market rather than a financial forward market like the Day-Ahead Energy Market. The Real-Time Energy Market is the environment in which the ISO control room commits and dispatches physical resources to meet actual real-time load, including the minute-to-minute balancing of energy and reserves while accounting for transmission system limits and the need to provide contingency coverage. While the financial schedules produced by the Day-Ahead Energy Market clearing process provide a starting point for the operation of the Real-Time Energy Market, the amount of supply needed and available at each location can increase or decrease for a number of reasons. First, all generators have the flexibility to revise their incremental energy supply offers during the reoffer period.[7] In addition, generating-unit and transmission line outages, along with unexpected changes in demand, can cause the ISO to call on additional generating resources to preserve the balance of supply and demand.

As part of its Reserve Adequacy Assessment (RAA) process, the ISO also may be required to commit additional generating resources to support local-area reliability or to provide contingency coverage, which ensures that the system reliably serves actual demand; the required operating-reserve capacity is maintained; and transmission line loadings are safe. For this process, the ISO evaluates the set of generator schedules produced by the Day-Ahead Energy Market solution, any self-schedules submitted during the reoffer period, and the availability of resources for commitment near real time. The ISO will commit additional generation if the scheduled Day-Ahead Energy Market generation, in addition to the self-scheduled resources and available off-line, fast-start generation, do not meet the real-time forecasted demand and reserve requirements that ensure system reliability. (See section below for more on reserves.)

All the circumstances that affect the level of generator dispatch, such as changes in the level of demand, actual generator availability, and system operating conditions, affect the real-time LMPs. At times, in import-constrained areas, where transmission interfaces limit the flow of economic energy, demand is high relative to local economic supply, and the ISO may need to call on more expensive generation. This results in higher LMPs in that area and lower LMPs on the export side of the interface. In contrast, relatively low-cost energy is available to serve load in export-constrained areas, which contain more low-priced capacity relative to local demand and export capacity, but this energy cannot be dispatched while respecting transmission limitations. These areas can experience lower LMPs compared with unconstrained areas that more readily can export excess supply. Financially, the settlement of the Real-Time Energy Market is based on the deviation between the day-ahead market outcome schedule and the actual production or consumption of electricity in real time.

[7] The *reoffer period* is the time spanning 4:00 p.m. and 6:00 p.m. on the day before the operating day (1:30 p.m. to 2:00 p.m. beginning on May 23, 2013, for the May 24 operating day) during which a market participant may submit revised resource offers.

# Forward Capacity Market

The Forward Capacity Market is a long-term wholesale market that assures resource adequacy, locally and systemwide. The market is designed to promote economic investment in supply and demand resources where they are needed most. Capacity resources may be new or existing resources and include supply from power plants, import capacity, or the decreased use of electricity through demand resources. To purchase enough qualified resources to satisfy the region's future needs and allow enough time to construct new capacity resources, Forward Capacity Auctions (FCAs) are held each year approximately three years in advance of when the capacity resources must provide service. Capacity resources compete in the annual FCA to obtain a commitment to supply capacity in exchange for a market-priced capacity payment.

This section describes the design of the Forward Capacity Market and FCAs as well as the financial-assurance mechanisms and oversight procedures in place for this market.

## Capacity Requirements

The capacity needed to satisfy the region's systemwide future load and reliability requirements is called the *Installed Capacity Requirement* (ICR).[8] The *net Installed Capacity Requirement* (NICR) values are the ICRs for the region, minus the tie-reliability benefits associated with the Hydro-Québec Phase I/II Interface (termed HQICCs).[9] Other key FCM inputs include locational capacity needs. These ensure that local areas secure sufficient capacity during the auction to maintain reliability when transmission constraints prevent the system from delivering the needed electric energy to the area. The transmission system constraints are based on the existing system network topology and transmission system upgrades certified by transmissions owners to be *in service* by the first day for the relevant capacity commitment period (CCP).[10] Transmission projects projected to go in service during the year are not included in the FCM auction assumption.

The locational information is provided for specific *capacity zones* (i.e., geographic subregions of the New England Balancing Authority Area that may represent load zones that are export constrained, import constrained, or contiguous—neither export nor import constrained). Import-constrained areas are assigned a *local sourcing requirement* (LSR) (i.e., the minimum amount of capacity that must be electrically located within these areas to meet the ICR). Export-constrained areas are assigned a *maximum capacity limit* (MCL)—the maximum amount of capacity that can be procured in these areas to meet the ICR.

During each FCA, existing capacity resources are limited to a service period of one capacity commitment period, while new resources may commit to as many as five such periods at the FCA price. Performance penalties for delivery shortfalls during the service period ensure that resources purchased through the auction will be available when needed.

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[8] The ICR is the total amount of installed capacity the system needs to meet the Northeast Power Coordination Council (NPCC) loss-of-load expectation criterion (LOLE) to not disconnect load more than once in 10 years. The ICR is calculated in accordance with *Market Rule 1*, Section III.12 and is filed with FERC before each auction. For additional information on the LOLE criterion, refer to ISO New England's Planning Procedure No. 3 (PP 3), *Reliability Standards for the New England Area Bulk Power Supply System* (March 1, 2013), http://www.iso-ne.com/rules_proceds/isone_plan/pp03/index.html, and NPCC criteria, https://www.npcc.org/Standards/default.aspx.

[9] As defined in the ISO's tariff, the HQICC is a monthly value that reflects the annual installed capacity benefits of the HQ Interconnection, as determined by the ISO using a standard methodology on file with FERC.

[10] *In service* is when a unit or transmission line is available for use. A *capacity commitment period*, also known as a *capability year*, runs from June 1 through May 31 of the following year.

## Resource Qualification

Because only resources with a capacity supply obligation (CSO) are required to offer into the Day-Ahead Energy Market, and because only the ICR amount is procured in the auction, it is critical for each FCA to procure only those capacity resources that will be commercial and available at the beginning of each capability year.[11] Although generating, demand, and import resources all may participate in the FCA to receive a CSO, the FCA treats new and existing capacity resources differently. Each type of resource has a distinctive qualification process designed to determine the amount of qualified capacity a particular resource can supply and to certify that each resource reasonably can be expected to be available during the relevant commitment period (approximately three years after the auction).

### Existing Capacity Resource Qualification

The qualification process for existing capacity resources begins with the ISO's determination of each resource's *summer* and *winter qualified capacity*.[12] For generating capacity resources, the qualified capacity value relies on a resource's demonstrated performance over the previous five years. The summer and winter qualified capacity values for demand resources are calculated based on the sum of the previous qualified existing capacity and any incremental capacity that clears in the prior FCA.

At least two weeks before the existing capacity qualification deadline, the ISO notifies existing resources of their qualified capacity to allow time for participants to verify that their qualified capacity is correct or to seek redress by demonstrating that a different capacity quantity is appropriate. All existing resources are included in the auction at the lower of their summer and winter qualified capacity, adjusted to account for applicable offers composed of separate resources. They also are automatically entered into the capacity auction and assume a capacity supply obligation for the relevant commitment period, unless they submit a "delist bid" that subsequently clears in the auction.

#### *Delist Bids*

An existing resource can submit a *delist bid* for opting out of the capacity market for one year or permanently if the auction were to fall below a certain price. Several types of delist bids exist:

- *Static delist bids* are submitted for a resource before the existing capacity qualification deadline, which occurs approximately eight months before an FCA. This type of delist bids are for resources opting to remove all or part of their total capacity from the market for a single commitment period at a price greater than or equal to $1.00/kW-month. They may reflect either the cost of the resource or a reduction in ratings resulting from ambient air conditions.[13] The ISO may be required to submit a static delist bid on behalf of a resource if the resource, or combination of resources using an offer composed of separate resources, will not be able to supply its awarded capacity during the entire commitment period. A lead participant may withdraw a static delist bid during a defined window, which occurs approximately four months before an FCA.

[11] A *capacity supply obligation* is a requirement for a resource to provide capacity, or a portion of capacity, to satisfy a portion of the ISO's Installed Capacity Requirement acquired through an FCA, a reconfiguration auction, or a CSO bilateral contract through which a market participant may transfer all or part of its CSO to another entity.

[12] The methodology for qualifying existing capacity resources is contained in *Market Rule 1*, Section III.13, http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_13-14.pdf.

[13] "Ambient air" delist bids are those made to reflect a thermal generator's difference in capacity rating at 90 degrees Fahrenheit (˚F) and at 100˚F.

- *Dynamic delist bids* are submitted by participants during an auction. Unlike other types of delist bids, dynamic delist bids are only offered below $1.00/kW-month, and the Internal Market Monitor does not oversee these bids (see below).

- *Permanent delist bids* represent a binding request to remove the resource's capacity from the capacity market permanently at a certain price. Capacity associated with a permanent delist bid may only reenter the capacity market if they qualify for, and clear, as a new resource in a subsequent FCA. Permanent delist bids are submitted for a resource before the existing capacity qualification deadline.

- *Nonprice retirement requests*, which are irrevocable requests to retire a resource, supersede any other delist bids submitted. Nonprice retirement requests are subject to a review for reliability impacts. If the ISO notifies a resource owner of a reliability need for the resource, the resource owner has the option to retire the resource as requested or continue to operate it until the reliability need has been met. Once the reliability need has been met, the resource must retire.

- *Export delist bids* are bids to exit the New England capacity market and sell capacity to a neighboring area. The cost of an export delist bid may include an opportunity-cost component of selling capacity to a neighboring market.

- *Administrative export delist bids* are submitted for capacity exports associated with multiyear contracts and are initiated using the same requirements as for export delist bids.

To provide market transparency to potential new capacity suppliers, all delist bids submitted during the qualification process are posted in advance of the FCA, with the exception of dynamic delist bids, which are submitted during the auction. The ISO reviews all delist bids for reliability purposes. Except for permanent delist bids and nonprice retirement requests, all delist bids are effective for the relevant commitment period only.

### *Internal Market Monitor Oversight*

To address market power concerns, during the qualification process, the IMM reviews certain delist bids to determine whether bid prices are consistent with a resource's net risk-adjusted going-forward costs and opportunity costs as specified in the rules. All delist bids, except dynamic delist bids, must include sufficient documentation for the Internal Market Monitor to make these determinations; the Internal Market Monitor may reject delist bids that have insufficient supporting documentation for the delist price. Static delist bids, export delist bids, and permanent delist bids above $1.00/kW-month are subject to Internal Market Monitor review. Delist bids submitted below $1.00/kW-month are presumed to be competitive.

The IMM does not review ambient air delist bids or administrative export delist bids. The IMM also does not review dynamic delist bids submitted during the auction at prices below 1.00/kW-month.

No later than 127 days before the auction, the ISO must notify participants regarding whether their delist bids are qualified to participate in the FCA. All accepted delist bids are entered into the auction. For delist bids excluded from the auction as a result of the Internal Market Monitor's review, the ISO will explain in the notification correspondence the specific reasons for not accepting the bid and the Internal Market

Monitor's derivation of an alternate delist price.[14] The participant may opt to use this alternate price, subject to applicable market rules and by informing FERC.

## Qualification Process for New Capacity Resources

Like existing resources, new supply-side and demand-side resources must undergo a qualification process to be able to participate in the FCM. Additionally, some resources previously counted as existing capacity (including deactivated or retired resources) and incremental capacity from existing resources may opt to be treated as new capacity resources in the FCA, subject to certain requirements.

To keep barriers to entry low and increase competition, the financial assurance required from new capacity suppliers is relatively low. A minimal level of credit enables more competitors to enter the market because they are not required to assume a relatively large financial guaranty during the project's development. However, because new commitments can be backed by a relatively low amount of financial security, they must undergo a rigorous qualification process and demonstrate that they can provide the capacity they plan to offer in the auction. This process ensures that any new project that clears in an auction can be interconnected before the delivery period and that the participant can back all capacity obligations with tangible assets to build the project.

### *New Supply-Side Resources*

For new power plant proposals, the ISO conducts several different power studies to ensure that a generator can connect to the power grid electrically without having a negative impact on reliability or violating safety standards. The qualification review also assesses the project's feasibility (i.e., whether it realistically can be built and commercialized before the beginning of the relevant capability year). The ISO also must evaluate each new supply-side resource to ensure that it will be able to provide effective incremental capacity to the system. An overlapping interconnection impact analysis for each new supply-side resource assesses whether the resource can provide useful capacity and electric energy without negatively affecting the ability of other capacity resources to provide these services also.

The first step to qualify a new capacity resource is for project sponsors to submit a new capacity show-of-interest (SOI) form. The SOI form is a short application that requests a minimum amount of information (e.g., interconnection point, equipment configuration, megawatt capacity). By the deadline for qualifying new capacity, the sponsor also must submit a completed qualification package for the project. This package must include all the data required for the ISO to evaluate the interconnection of the project and its feasibility. Also at this time, new import-capacity resources must provide documentation indicating the interface from which the capacity will be imported, the source of the capacity (from an external generating resource or from an adjacent balancing authority area), and the import's summer and winter capability ratings.

### *New Demand-Side Resources*

Demand-reduction resource proposals undergo a feasibility review, during which the ISO ensures that the plans and methods for reducing electricity use meet industry standards. This is the primary mechanism for assessing demand-response project criteria because these projects have no interconnection impact.[15] For this review, demand resources submit a measurement and verification

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[14] FERC's FCM Settlement Agreement contained the thresholds for delist bids requiring IMM review: *Order Accepting in Part and Modifying in Part Standard Market Design Filing and Dismissing Compliance Filing,* Docket Nos. ER02-2330-000 and EL00-62-039 (September 20, 2002), 37, http://www.iso-ne.com/regulatory/ferc/orders/2002/sep/er022330-000.pdf.

[15] *Demand response* is when a market participant reduces its consumption of electric energy from the network in exchange for compensation based on wholesale market prices.

plan, which outlines the project and its development and how the resource will achieve the demand reduction. The ISO subsequently reviews this plan for completeness and to determine how much capacity the resource can provide.

### *Internal Market Monitor Oversight*

Per *Market Rule 1*, new resources are given a stated price, known as the offer-review trigger price (ORTP), up to which point the resource may remain within the auction. The IMM developed a menu of ORTPs for various resource types, which approximate the net cost of entry of each resource. The ORTP establishes a floor price for a new resource, below which it must leave the auction, absent a request submitted to the IMM to offer at a price lower than the relevant ORTP. New resources that might submit offers in the FCA at prices below the relevant ORTP must include in the new capacity qualification package the lowest price at which the resource requests to offer capacity, along with supporting documentation justifying that price as competitive in light of the resource's costs. If the IMM determines that the offer is consistent with the long-run average costs, the resource will be allowed to remain in the auction up to the validated price.

### *Notification and Filing*

No later than 127 days before each FCA, the ISO notifies each sponsor engaged in the qualification process regarding whether its new capacity resource has been accepted for participation in the FCA. If accepted, the ISO also notifies the sponsor of the qualified capacity of that resource and the Internal Market Monitor's assessment, if the sponsor intends to offer the resource below its ORTP. Additionally, the ISO files all qualification results and auction inputs with FERC. This informational filing is made approximately three months before the ISO conducts the auction and provides interested parties the opportunity to review and comment on the ISO's fulfillment of its responsibilities before conducting the FCA.

## Auction Design

Each Forward Capacity Auction is conducted in two stages; a descending-clock auction followed by an auction clearing process. The descending-clock auction, run by an auctioneer, consists of multiple rounds. Before the beginning of each round, the auctioneer announces to all participants the start-of-round and end-of-round prices. During the round, participants submit offers expressing their willingness to keep specific megawatt quantities in the auction at different price levels within the range of the start-of-round and end-of-round prices. During one of the rounds, the capacity willing to remain in the auction at some price level will equal or fall below the net Installed Capacity Requirement. FCM resources still in the auction at this point pass on to the auction-clearing stage.

Table 1 shows the hypothetical result of a descending-clock FCA with a starting price of $15.00/kW-month. Additional assumptions built into this example are that the NICR equals 30,000 MW; 23,000 MW of existing capacity will be participating, thus 7,000 MW of new resources will be needed to meet the NICR; and 10,000 MW of new capacity will be participating.

**Table 1**
**Sample Results from a Descending-Clock Forward Capacity Auction**

| Round | Start-of-Round Price ($/kW-mo) | End-of-Round Price ($/kW-mo) | End-of-Round Resource (MW) | Excess Capacity (MW) |
|---|---|---|---|---|
| **1** | $15.00 | $9.50 | 33,000 | 3,000 |
| **2** | $9.49 | $9.00 | 32,500 | 2,500 |
| **3** | $8.99 | $8.00 | 32,000 | 2,000 |
| **4** | $7.99 | $7.50 | 31,000 | 1.000 |
| **5** | $7.49 | $7.00 | 30,750 | 750 |
| **6** | $6.99 | $6.00 | 29,800 | −200 |

All the capacity resources remaining in the auction at the end of round six pass through to the second stage of the FCA. In this stage, the market-clearing auction software is run to determine the minimal capacity payment and calculate final capacity-zone clearing prices. This step also includes a post-processing procedure that determines the final payment rate for each resource and its capacity supply obligation for the capacity commitment period. Thus, using the example shown in Table 1, after the sixth round, the market-clearing auction software would be run to determine the resources and the price that would minimize the cost at a purchase amount of 30,000 MW. The final capacity-zone clearing price in this example would equal some value between the round six start-of-round price and end-of-round price.

Reconfiguration auctions take place before and during the commitment period to allow participants to buy and sell capacity obligations and adjust their positions. These auctions are needed to add capacity to cover for potential increases in the ICR, to release capacity to match potential decreases in the ICR, and to defer capacity requirements associated with existing capacity delist bids. Annual reconfiguration auctions (ARAs) to acquire one-year commitments are held approximately two years, one year, and just before the FCA commitment period begins. Monthly reconfiguration auctions, held beginning the first month of the first commitment period, adjust the annual commitments during the commitment period.

## Capacity Payments

Resources with capacity supply obligations are paid the auction clearing price. However, two key provisions of the capacity payment structure are the *peak energy rent* (PER) adjustment and penalties incurred for unavailability during *shortage events*. The PER adjustment reduces capacity market payments for all capacity resources when prices in the electric energy markets go above the PER threshold (i.e., *strike*) price, which is an estimate of the cost of the most expensive resource on the system. This usually occurs when electricity demand is high. PER provides an additional incentive for capacity resources to be available during peak periods because capacity payments are reduced for all listed resources, even those not producing energy when the LMP exceeds the PER threshold price. PER also discourages physical and economic withholding in the energy market because a resource that withholds to raise price does not earn energy revenues, while its foregone revenues are deducted from the capacity market settlement.

*Shortage events* are periods when reserves fall below the system reserve requirements for 30 minutes or more. Shortage-event availability penalties are assessed for resources with capacity supply obligations unavailable during defined shortage events. The availability penalties are a disincentive to withhold in the energy market.

# Reserve Markets

To maintain system reliability, all bulk power systems, including ISO New England, need reserve capacity to be able to respond to contingencies, such as those caused by unexpected outages. *Operating reserves* are the unloaded capacity of generating resources—either off line or on line—that can deliver electric energy within 10 or 30 minutes.[16]

ISO operating procedures require reserve capacity to be available within 10 minutes to meet the largest single system contingency (N-1). A resource's ability to provide 10-minute reserve from an off-line state is referred to as "claim-10" capability.[17] Additional reserves must be available within 30 minutes to meet one-half of the second-largest system contingency (N-1-1). The ISO also identifies local second-contingency-protection resources (LSCPRs) to meet the second-contingency requirements in import-constrained areas of New England. A resource's ability to provide 30-minute reserve from an off-line state is referred to as "claim-30" capability. In general, capacity equal to between one-fourth and one-half of the 10-minute reserve requirement must be synchronized to the power system, or be *10-minute spinning reserve* (TMSR), while the rest of the 10-minute requirement may be *10-minute nonspinning reserve* (TMNSR). The entire 30-minute requirement may be served by *30-minute operating reserve* (TMOR) or the higher-quality 10-minute spinning reserve or nonspinning reserve. In addition to the systemwide requirements, 30-minute reserves must be available to meet the local second contingency in import-constrained areas.

In the New England system, participants with resources that provide reserves are compensated through both the locational Forward Reserve Market, which offers a product similar to a capacity product, and real-time reserve pricing. The FRM obligates participants to provide reserve capacity in real time through a competitive, intermediate-term forward-market auction. When the ISO dispatches resources in real time and sets LMPs, the process co-optimizes the use of resources for providing electric energy and real-time reserves. When resources are dispatched to a lower level in real-time to provide reserve capacity rather than electric energy, a positive real-time reserve price for the product is set, recognizing the resource's opportunity cost of providing reserve rather than energy. The real-time reserve prices also reflect additional costs to the system for dispatching some other, more expensive resource to provide electric energy to replace the output of the resource that was dispatched down.

The New England system has reserve requirements for its locational FRM and real-time operations. There are systemwide requirements for TMSR, TMNSR, and TMOR. TMOR requirements exist for reserves in the region's four reserve zones—Connecticut (CT), Southwest Connecticut (SWCT), NEMA/Boston, and the rest of the system (Rest-of-System, ROS). The *Rest-of-System* zone is defined as the area excluding the other, local reserve zones.

This section provides an overview of the locational Forward Reserve Market for procuring reserve obligations for winter and summer periods. It also discusses *real-time reserve pricing*, which compensates resources that provide reserves needed in real time, and the ISO's implementation of scarcity pricing.

[16] Some demand-side resources also can provide reserves; see section below.

[17] After a unit is upgraded or maintained, it may request a reaudit to have its improved reliability reflected in its claimed values. Changes in total claim-10 and claim-30 capability also can result from new or existing units demonstrating their capability or any time the ISO requests a unit to start.

## Forward Reserve Market

The Forward Reserve Market is designed to attract investments in, and compensate for, the type of resources that provide the long-run, least-cost solution to satisfying off-line reserve requirements. The locational FRM compensates participants with resource capacity located within specific subareas for making the type of electric energy market offers that would make them likely to be unloaded and thus available to provide energy within 10 or 30 minutes. Typically, these resources are fast-start units that run infrequently throughout the year (i.e., they have low capacity factors).[18] However, the FRM also compensates resources that commit to be on line without Net Commitment-Period Compensation (NCPC) and have upper portions of the dispatch range that typically are unloaded.[19]

The ISO conducts two FRM auctions, one each for the summer and winter reserve periods (June through September and October through May, respectively), that acquire obligations to provide prespecified quantities of each reserve product. Forward-reserve auction clearing prices are calculated for each reserve product in each reserve zone. When supply offers for forward reserve are not adequate to meet a requirement, the clearing price for that product is set to the price cap, which is $14.00/kW-month.[20] When enough supply is offered under the price cap to meet the requirement for a product in a particular zone, the auction clearing price for that product is set equal to the price of the marginal supply offer. To avoid compensating the same resource megawatt as both general capacity and forward-reserve capacity, actual FRM payments to participants are reduced by the FCA clearing price.

To attract and maintain resources that normally are expected to provide reserves instead of electric energy, the FRM requires the resources designated as forward-reserve resources to offer the megawatt quantity of energy equal to the FRM obligation at or above a threshold price. Participants would not be expected to designate resources that normally are in merit below this level because they would forego the energy revenue from operating.[21] Conversely, designating high-incremental-cost peaking resources does not create a lost opportunity cost because the ISO would not dispatch the resource to provide energy under normal circumstances.

The forward-reserve auction clears megawatt obligations that are not resource specific. Before the end of the reoffer period for the Real-Time Energy Market, participants submit electric energy offers that exceed a threshold price for designated resources they control to satisfy the obligation. Before midnight of the day before the operating day, participants that win obligations in a forward-reserve auction must assign physical resources to satisfy their FRM obligations.

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[18] A *capacity factor* is the ratio of the electric energy a generating unit produced for a certain period to the electric energy it could have produced at full operation during the same period.

[19] *Net Commitment-Period Compensation* is a method of providing 'make-whole' payments to market participants with resources dispatched out of economic-merit order for reliability purposes when the costs of providing energy or reserves from the resources would otherwise exceed the revenue paid to the market participant. NCPC is paid to resources for providing first- and second-contingency voltage support and control as well as distribution system protection in either the Day-Ahead or Real-Time Energy Markets. The accounting for the provision of these services is performed daily and considers a resource's total offer amount for generation, including start-up fees and no-load fees, compared with its total energy market value during the day. If the total value is less than the offer amount, the difference is credited to the market participant. For more information, see *Market Rule 1*, Appendix F, "Net Commitment-Period Compensation Accounting" (January 3, 2012), http://www.iso-ne.com/regulatory/tariff/sect_3/.

[20] *Market Rule 1*, Section III.9.4, "Forward Reserve Auction Clearing and Forward Reserve Clearing Prices" (March 16, 2011), http://www.iso-ne.com/regulatory/tariff/sect_3/.

[21] *Economic-merit order* (i.e., *in merit* or *in merit order*) is when the generators with the lowest-price offers are committed and dispatched first, and increasingly higher-priced generators are brought on line as demand increases.

The intent of the market design is to set threshold prices to approximate the marginal cost of a peaking resource with an expected capacity factor of 2 to 3%.[22] If the threshold price is set accurately, LMPs should exceed the threshold price only 2 to 3% of the time. A resource offered at exactly the threshold will be dispatched only when the LMP exceeds the threshold price. If the threshold price is set too low, a forward-reserve-designated unit offered at the threshold price will be dispatched to provide electric energy more frequently and therefore will be unavailable to provide reserve. If this occurs more than 2% to 3% of the time, forward-reserve-designated resources will be dispatched more frequently than intended.[23] If participants expected LMPs to be higher than the threshold price regularly, the reserve market could inadvertently attract resources better suited to provide electric energy than reserve.

Bilateral transactions, as well as any reserve-capable resource in the participant's portfolio, can meet the reserve obligations incurred in the auction. Bilateral trading of forward-reserve obligations allows suppliers facing unexpected unit outages to substitute alternative resources. This feature is useful to suppliers if the cost of expected penalties for nondelivery exceeds the cost of acquiring substitute resources through bilateral transactions. Failure to designate a unit they control or the transfer of the obligation to another participant results in the assessment of a "failure-to-reserve" penalty.

The locational FRM acquires only those resources needed to satisfy off-line reserve requirements, namely TMNSR and TMOR; spinning reserve is not acquired in the forward market. The allocation of the costs for paying resources to provide reserves is based on real-time load obligations in load zones.[24] These obligations are price-weighted by the relative forward-reserve clearing prices of the reserve zones that correspond to each load zone.[25]

## Real-Time Reserve Pricing

The reliable operation of the system requires that real-time operating reserves be maintained for the system as a whole and for identified transmission-import-constrained areas.[26] The ISO's operating-reserve requirements, as established in Operating Procedure No. 8, *Operating Reserve and Regulation* (OP 8), protect the system from the impacts associated with a loss of generating or transmission equipment within New England.[27] According to OP 8, the ISO must maintain a sufficient amount of reserves to be able to recover from the loss of the first contingency within 10 minutes.

[22] The formula for determining the forward-reserve threshold price is fixed for the duration of the forward-reserve period. This price changes monthly with fuel-price indices and is calculated as a heat rate multiplied by a fuel index. The forward-reserve heat rate also is fixed in the auction notice and does not change during the forward-reserve service period. The threshold price calculation uses the lesser of an index for No. 2 fuel oil and one for natural gas. (A generator's *heat rate*, traditionally reported in Btu/kilowatt-hour (kWh), is the rate at which it converts fuel [Btu] to electricity [kWh] and is a measure of the thermal efficiency of the conversion process.)

[23] A threshold price can be lower than the LMP more than the intended 2 to 3% of the time if the fuel index used in calculating the threshold price is lower than actual fuel prices. The 2 to 3% target also can be surpassed if the system is tighter than expected more frequently, thus requiring the dispatch of less efficient resources. In this case, LMPs will be higher.

[24] *Market Rule 1 Accounting*, Manual 28 (February 6, 2012), http://www.iso-ne.com/rules_proceds/isone_mnls/.

[25] The forward-reserve prices for the ROS reserve zone are used to calculate the charges allocated to load-serving entities in the ME, NH, VT, RI, SEMA, and WCMA load zones. The forward-reserve prices for the SWCT and CT reserve zones are used to calculate the charges allocated to LSEs in the CT load zone, while the forward-reserve prices for the NEMA/Boston reserve zone are used to calculate the charges allocated to the NEMA load zone.

[26] Refer to the ISO's RSP12 for additional information on operating-reserve requirements; http://www.iso-ne.com/trans/rsp/2012/index.html.

[27] Operating Procedure No. 8, *Operating Reserves and Regulation* (March 11, 2013), http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html.

In real time, the ISO dispatches resources in the least-cost way to meet the system's requirements for electric energy and reserves simultaneously. The system has real-time reserve requirements (in MW) for the following reserve categories:

- System 10-minute spinning reserves
- System 10-minute nonspinning reserves
- System 30-minute operating reserves
- Zonal TMOR for each reserve zone other than the ROS zone

Reserve pricing optimizes the use of local transmission capabilities and generating resources to provide electric energy and reserves. This allows the dispatch software to choose whether transmission should be used to carry electric energy or left unloaded to provide reserves that satisfy zonal reserve requirements. This optimization is based on the real-time energy offers of resources; there are no separate real-time reserve offers. *Real-time reserve credits* are the revenues paid to participants with resources providing reserve during periods with positive real-time reserve prices.

Reserves may be allowed to decline below requirements in real time, such as during ISO Operating Procedure No. 4 (OP 4), *Action during a Capacity Deficiency*, if capacity is short and the system cannot be redispatched to maintain reserve.[28] Before allowing reserves to decline, the system will redispatch resources to maximize the amount of reserves available. Redispatch typically involves decreasing the output of units with fast ramping capabilities that were providing electric energy and increasing the output of slower, more expensive units to replace this energy. The result is the decrease in electric energy output of the faster-ramping resources to provide reserves and the replacement of this lost energy with output from higher-cost resources, which results in higher electric energy prices (i.e., LMPs). The resulting real-time reserve prices represent the scarcity of reserves on the system. Local reserve shortages resulting from a complete capacity deficiency are rare. In most cases, reserves can be maintained through the process of redispatch, with appropriate compensation through real-time reserve pricing.

*Reserve Constraint Penalty Factors* (RCPFs) are administratively set limits on redispatch costs ($/megawatt hour; $/MWh) the system will incur to meet reserve constraints. Each reserve-requirement constraint has a corresponding RCPF, shown in Table 2. The RCPFs are cumulative; the total redispatch cost the system will incur to preserve TMSR is the sum of the RCPFs for TMSR, TMNSR, and TMOR. Similarly, the total redispatch cost the system will incur to preserve TMNSR is the sum of the RCPFs for TMNSR and TMOR. The following table lists the RCPF values.

**Table 2**
**New England Reserve Constraint Penalty Factors ($/MWh)**

| Constraint | Reserve Constraint Penalty Factor |
|---|---|
| **Systemwide TMSR constraint** | 50 |
| **Systemwide total 10-minute reserve constraint** | 850 |
| **Systemwide total 30-minute reserve constraint** | 500 |
| **Local 30-minute reserve constraint** | 250 |

[28] The OP 4 guidelines contain 16 actions that can be implemented individually or in groups depending on the severity of the situation. OP 4 is available at http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

# Regulation Market

*Regulation* is the capability of specially equipped generators and other energy sources to increase or decrease their output every four seconds in response to signals they receive from the ISO to control slight changes on the system. This capability is necessary to balance supply levels with the second-to-second variations in demand and to assist in maintaining the frequency of the entire Eastern Interconnection.[29] This system balancing also maintains proper power flows into and out of the New England Balancing Authority Area.

The primary objective of the Regulation Market, which is the mechanism for selecting and paying resources needed to manage system balancing, is to ensure that the ISO meets the North American Electric Reliability Corporation's (NERC) *Real Power Balancing Control Performance Standard* (BAL-001-0) for balancing authority areas.[30] The primary measure used for evaluating control performance is Control Performance Standard 2 (CPS 2), which is as follows:[31]

> *Each balancing authority shall operate such that its average area control error (ACE) for at least 90% of clock-10-minute periods (six nonoverlapping periods per hour) during a calendar month is within a specified limit, referred to as $L_{10}$.*[32]

For the New England Balancing Authority Area, the CPS 2 annual average compliance target is 92 to 97%. The ISO periodically evaluates the regulation requirements necessary to maintain CPS 2 compliance. The regulation requirements (posted on the ISO's website) are determined by hour and vary by time of day, day of week, and month.[33]

The regulation clearing price (RCP) is calculated in real time and is based on the regulation offer of the highest-priced generator providing the service. Compensation to generators that provide regulation includes a regulation capacity payment, a service payment, and a unit-specific opportunity cost payment.[34] Unit-specific opportunity cost payments are not included as a component of the regulation clearing price.

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[29] The *Eastern Interconnection* is one of North America's major AC grids that, during normal system conditions, interconnects transmission and distribution infrastructure synchronously operating (at 60-hertz average) east of the Rocky Mountains and south to Florida, excluding Québec and the portion of the system located in the Electric Reliability Corporation of Texas (ERCOT).

[30] This standard (effective May 13, 2009) can be accessed at http://www.nerc.com/page.php?cid=2|20. Additional information on NERC requirements is available at http://www.nerc.com.

[31] More information on NERC's Control Performance Standard 2 is available at http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf (Resource and Demand Balancing; BAL).

[32] The *area control error* is the instantaneous difference between the net actual and scheduled interchange (i.e., transfer of electric energy between two balancing authority areas), accounting for the effects of frequency bias and correction for meter error. ACE must be restored to its predisturbance value within 15 minutes, and operating reserves must be restored, as required by the NERC's BAL-002-0, "Resource and Demand Balancing," disturbance control standard (April 1, 2005), http://www.nerc.com/files/BAL-002-0.pdf. The ACE of the New England Balancing Authority Area is the actual net interchange minus the biased scheduled net interchange; see *ISO New England Manual for Definitions and Abbreviations—Manual 35*; http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

[33] The ISO's regulation requirements are available at http://www.iso-ne.com/sys_ops/op_frcstng/dlyreg_req/index.html.

[34] A *regulation opportunity cost payment* is compensation to a pool-scheduled generator for providing regulation service during all or a portion of an hour.

# Reliability Commitments and Costs

To maintain daily system reliability, the ISO is required to make generator commitments that supplement the market-clearing outcomes. Resources that the ISO requests to operate out of merit or that do not fully recover short-run operating costs receive Net Commitment-Period Compensation. To maintain long-term reliability, the ISO also administers FERC-approved agreements, called Reliability Cost-of-Service Agreements (Reliability Agreements), with certain generator owners. This section discusses the types of reliability commitments and the process for making these commitments and allocating costs for resources committed to supplement the market-clearing process.

## Daily Reliability Requirements, Commitments, and Costs

The requirements for ensuring the reliability of New England's bulk power system reflect standards developed by NERC, NPCC, and the ISO through open stakeholder processes.[35] These requirements are codified in the NERC standards, NPCC criteria, and the ISO's operating procedures.[36] To meet these requirements, the ISO may commit resources in addition to those cleared in the Day-Ahead Energy Market.

The ISO may commit and dispatch generation to create reserves that allow the system to recover from the loss of the first contingency within the specified period by providing energy on short notice. Not having these resources committed to operate would pose a threat to the reliability of the system. Generators also can be committed to provide systemwide stability or thermal support or to meet systemwide electric energy needs during the daily peak hours. All generators have a minimum run time, and resources committed for peak hours often are still on line after the peak hours to satisfy minimum run-time requirements. The ISO also may commit resources to support second contingencies, to provide reactive power for voltage control or support, or to support local distribution networks. Resources that operate because the ISO requires them to do so but do not recoup their full operating costs (represented by their three-part offers) through electric energy market revenues are paid one of the following types of compensation:

- First-contingency Net Commitment-Period Compensation
- Local second-contingency Net Commitment-Period Compensation
- Voltage reliability payments
- Distribution reliability payments

Systemwide first-contingency costs are financially settled through first-contingency reliability payments paid by the entire system. Local second-contingency commitments costs are settled at the zonal level. The cost of resources committed to provide reactive power for voltage control or support are allocated to transmission owners locally for high voltage and systemwide otherwise. Local transmission-support costs are allocated to the transmission owner requesting the commitment.

## Reliability Commitment Process

Electric energy market outcomes play an important role in determining the need for out-of-market commitments for reliability. While market participants can make some commitments before or

[35] For more information on NERC standards, see http://www.nerc.com/page.php?cid=2|20. For more information on NPCC standards, https://www.npcc.org/Standards/default.aspx.

[36] The ISO's system operating procedures are available at http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

immediately after the Day-Ahead Energy Market clears as part of the ongoing Reserve Adequacy Assessment, they make most commitments after the reoffer period or later in the RAA process (see section above). This process is designed to maximize the opportunity for the market to respond to the need to ensure reliability and to minimize the ISO's supplemental commitments to meet reliability criteria. The results of the RAA are used to add or cancel commitments during the operating day if reliability needs change because of market response or other changed system conditions. When multiple generators are available to meet the RAA requirements, the ISO process selects the resources that will have the lowest total cost for starting and operating the resource at its minimum load for its minimum run time. To the extent that market outcomes and resource self-scheduling result in the commitment of resources needed for local reliability, the ISO does not manually have to commit resources for second-contingency or voltage services.

## Reliability Commitment Compensation

Reliability payments are calculated in both the Day-Ahead Energy Market and the Real-Time Energy Market. First-contingency and second-contingency NCPC payments, voltage-reliability payments, and distribution-reliability payments are made to eligible pool-scheduled generators whose output is constrained above or below the economic level, as determined by the LMP in relation to their offers. This compensation is based on a daily calculation comparing the generators' submitted offer cost for providing electric energy, including start-up and no-load offers and incremental energy offers, to the resources' total energy market revenues for the day. This ensures that generators will follow dispatch instructions made to provide reliability even if a daily loss will result in the energy market at the offer cost. In the electricity industry, these payments are sometimes referred to as *uplift*.

If a generator operates in economic-merit order, most of its compensation will be from the electric energy market. While generators committed to ensure first-contingency coverage (systemwide reliability) may have been in merit during peak hours, they may be out of merit in other hours and will receive first-contingency reliability payments. Alternatively, electric energy market revenues may have been insufficient to cover start-up costs and no-load costs for resources dispatched in economic-merit order to provide energy. First-contingency reliability payments are paid to resources committed by the ISO that do not recover the short-term variable operating costs for the day and are not designated to provide second-contingency reliability or to meet requirements for voltage or distribution system reliability.

## Daily Reliability Cost Allocations

The out-of-market costs associated with daily reliability payments to generators are allocated to market participants. Section II of the ISO tariff (*Open Access Transmission Tariff*) governs the allocation of voltage and distribution payments, whereas Section III of the tariff (*Market Rule 1*) governs the allocation of first- and second-contingency payments.[37] According to the ISO tariff, all New England transmission owners share voltage payments on the basis of network load, and distribution payments are assigned directly to the transmission owners requesting the generator commitment to protect their distribution system.

First-contingency reliability costs in the Day-Ahead Energy Market are charged to participants in proportion to their day-ahead load obligations. In the Real-Time Energy Market, participants are charged in proportion to these deviations if their real-time load deviates from the day-ahead schedule or if their generators deviate from day-ahead schedules and they are not following real-time dispatch instructions. Second-contingency reliability costs in the Day-Ahead and Real-Time Energy Markets generally are

[37] The ISO tariff and its subsections are available at http://www.iso-ne.com/regulatory/tariff/index.html.

charged to participants in proportion to their load obligations in the respective markets. As part of a 2007 FERC Settlement Agreement, a two-condition, two-tiered threshold criterion was established that could change the allocation of real-time second-contingency charges, such that the charges are allocated to both network load and load obligation.[38]

# Financial Transmission Rights

As mentioned, transmission constraints can lead to price differences between different system locations. In addition, the LMPs throughout the system can be divided into a marginal cost of energy, which is constant across all nodes; the marginal cost of congestion, which is a measure of the cost of transmission congestion; and the marginal cost of physical transmission losses. The FTR markets and auction revenue distribution rules were designed to allow participants to hedge physical day-ahead congestion costs and to arbitrage FTR auction prices to the expected cost of future congestion. This section discusses the FTR auctions that provide a market-based allocation of future congestion revenue and the administrative distribution of the revenues from these auctions.

## FTR Markets

The *financial transmission right* instrument entitles the holder to receive, over a monthly or annual period, a stream of revenues (or obligates it to pay a stream of costs) that arise when the transmission grid is congested in the Day-Ahead Energy Market. The amount is based on the difference between the day-ahead congestion components of the hourly LMPs at each of the two pnodes that define the FTR and its megawatt quantity acquired in the FTR auctions.[39] Participants can acquire FTRs for any path on the system defined by two pricing locations. The origin location of an FTR is called the *source* point, and the FTR delivery location is called the *sink* point. The price of a particular FTR is equal to the difference between the prices at the sink location and the source location in the FTR auction.

The ISO conducts one annual and 12 monthly FTR auctions for buying and selling FTRs. Annual FTRs are offered in a single auction for the ensuing year, and additional monthly FTRs are offered before each month during the year. The auction process also allows participants that may not have physical energy obligations to arbitrage differences between the expected value of an FTR path, defined by the auction price, and the actual value of the FTR path (i.e., the difference between day-ahead congestion components of the source and sink nodes that define the FTR path). Efficient auction outcomes are those that result in average path profits that have a risk-adjusted profit of zero for both on-peak and off-peak FTRs.

The annual FTR auction makes available up to 50% of the transmission system capability expected to be in service during the year. In monthly auctions, up to 95% of the expected transmission capability for the month is available. The total volume of FTRs transacted in each auction is a function of the offers and bids submitted subject to the transmission limits modeled.

## FTR Settlements

Hourly congestion revenues from both the Day-Ahead and Real-Time Energy Markets are accumulated in the Congestion Revenue Balancing Fund (CRBF). Day-ahead congestion for any hour will be a positive value if transmission constraints contribute to price separation on the system. In real time, congestion

[38] FERC, *Letter Order Accepting ISO New England Inc.'s 5/18/07 Filing of a Rate Schedule in the Form of an Agreement Reached by the ISO-NE etc, Effective 7/1/07 under ER07-921,* Docket No. ER07-921-000 (June 21, 2007).

[39] The minimum quantity for an FTR is 0.1 MW.

revenue can be either positive or negative because the real-time market settles on deviations from day-ahead schedules.

Whenever congestion exists on the system in the Day-Ahead Energy Market, every FTR will have an hourly positive target allocation (PTA) or negative target allocation (NTA) that accumulates in the CRBF along with day-ahead and real-time congestion revenues. A *positive target allocation* is created when the congestion component at the sink location of the FTR is greater than the congestion component at the source location of the FTR. Holders of FTRs with positive target allocations are owed payments from the CRBF. A *negative target allocation* is created when the day-ahead sink congestion component of an FTR is less than the FTR's source congestion component. An FTR with a negative target allocation becomes a counterflow settlement with payments due to the CRBF.

The only connection that CRBF target allocations have to the FTR auctions are the megawatt quantities along with the source and sink locations of the FTRs. The prices paid and whether the FTRs were purchased with a negative value (i.e., counterflow FTRs) or a positive value (prevailing-flow FTRs) are irrelevant to the monthly settlement of the FTRs.

## Auction Revenue Distribution

The revenue collected during the FTR auctions is distributed to market participants. The ISO tariff includes provisions that allocate this FTR auction revenue back to congestion-paying load-serving entities and transmission customers or owners that have supported the transmission system. The tariff provides two broad classes of participants for the allocation of auction revenues: holders of Qualified Upgrade Awards (QUAs) and holders of Auction Revenue Rights (ARRs). QUAs are assigned to entities that have improved the system's transmission capacity through specific projects, such as generation interconnections, and have accepted QUAs as compensation for a portion of the construction and maintenance of the improved infrastructure rather than network service rights payments. ARRs are the mechanism used to distribute the remainder of the auction revenue to congestion-paying LSEs and transmission customers that have supported the transmission system.

The costs associated with the FTR markets—the administrative costs of holding FTR auctions and settling the FTRs and the potential cost of participants' defaulting on their FTR portfolios—are passed through ISO tariff charges to those with transactions in the FTR market.

# Demand Resources

Along with adequate supply and robust transmission infrastructure, demand resources are an important component of a well-functioning wholesale market. The equipment, systems, services, and strategies that constitute demand resources may include measures at individual customer facilities to reduce end-use demand during specific hours or a portfolio of measures to reduce demand.

While the wholesale electricity markets account for differences in costs of supply that vary with the time and location of consumption, demand resources account for differences in costs of service that vary among customers. Demand resources of all types may provide relief from capacity constraints and promote more economically efficient uses of electrical energy. In the Forward Capacity Market, some types of demand-response resources are paid capacity payments and can compete in the Forward Capacity Auction, as do other supply-side resources. For example, some customers can reduce their overall energy usage while maintaining the same level of productivity and comfort by implementing energy-efficiency measures. Other customers can supply capacity by eliminating their consumption on short notice in response to a capacity deficiency. Still others may be able to shift end-use customer load onto an on-site emergency generator in response to system emergencies.

The ISO has two broad categories of demand resources: active and passive. *Active demand resources* are dispatchable and respond to ISO dispatch instructions, while *passive demand resources* provide load reductions during previously established performance hours. The ISO-administered demand-resource programs fall into three basic categories: active demand resources that reduce load to support system reliability, active demand resources that respond to wholesale energy prices, and passive demand resources that reduce load through energy efficiency and similar measures. The ISO's special-purpose demand-response programs differentiate demand-resource owners by cost. This type of customer differentiation arises naturally in competitive markets whenever customer costs differ, and it allows lower-cost customers to reap the benefits of their lower costs. Programs that promote demand resources complement the wholesale electricity markets by offering program choices that recognize different customer costs and capabilities.

The ISO administered the following active-demand-resource programs during 2012:

- **Real-Time Demand-Response Resources—**a program in which resources must curtail electrical usage within 30 minutes of receiving a dispatch instruction from the ISO. These resources are dispatched when the ISO forecasts OP 4 Action 2 or higher the day before the operating day, or implements OP 4 Action 2 or higher during the operating day. OP 4 Action 2 is the action the ISO takes to dispatch real-time demand resources (RTDRs) in the amount and location required in response to the depletion of 30-minute operating reserve. Registered real-time demand-response assets have the option of participating in the Day-Ahead Load-Response Program (DALRP) (see below).
- **Real-Time Emergency Generation Resources (RTEG)—**distributed generation the ISO calls on to operate during a 5% voltage reduction that requires more than 10 minutes to implement (i.e., OP 4 Action 6 or more severe actions) but must limit its operation to 600 MW to comply with the generation's federal, state, or local air quality permit(s) and the ISO's market rules. RTEG operations result in curtailing load on the grid as the distributed energy provided by the emergency generator begins serving demand. Real-time emergency generators must be available from 7:00 a.m. to 7:00 p.m. Monday through Friday on nonholidays, they must begin operating within 30 minutes of receiving a dispatch instruction, and they must continue operating until receiving an ISO instruction to shut down.
- **Real-Time Price-Response Program (program ended on May 31, 2012)—**a separate real-time demand-response program that involves voluntary load reductions by program participants eligible for payment when the day-ahead or forecast hourly real-time LMP is greater than or equal to $100/MWh and the ISO has transmitted instructions that the eligibility period is open. Participants are paid the higher of $100/MWh or the real-time LMP.
- **Day-Ahead Load-Response Program (program ended on May 31, 2012)—**an optional program that allows participants enrolled in the active-demand-resource category that reduce load to support system reliability (with the exception of RTEG resources) and participants enrolled in the Real-Time Price-Response Program to offer interruptions in response to Day-Ahead Energy Market prices. If an offer clears, the participant is paid the day-ahead LMP and is obligated to reduce load by the day-ahead amount cleared.[40] The participant then is charged or

[40] This clearing process takes place after the close of the Day-Ahead Energy Market and does not play a role in setting the day-ahead LMPs.

credited at the real-time LMP for any real-time deviations in curtailment relative to the day-ahead amount cleared.

- **Transitional Price-Responsive Demand (program began June 1, 2012)—**a new "transitional" program, designed to comply with FERC Order 745, anticipated to remain in effect until June 1, 2017, at which time new market rules will become effective that will fully integrate dispatchable demand resources into the Day-Ahead and Real-Time Energy Markets.[41] Similar to the DALRP, this optional program allows market participants with assets registered as RTDRs to offer load reductions in response to day-ahead LMPs. Market participants are paid the day-ahead LMP for their cleared offers and are obligated to reduce load by the amount cleared day ahead. The participant is then charged or credited at the real-time LMP for any deviations in curtailment in real time compared with the amount cleared day ahead.

In passive-demand-resource programs, resources do not receive dispatch instructions from the ISO. Instead, they curtail their electricity use at set times throughout the year. The ISO administered the following passive-demand-resource programs during 2012:

- **On-peak resources—**reduce consumption during summer peak hours (nonholiday weekdays, 1:00 p.m. to 5:00 p.m., during June, July, and August) and winter peak hours (nonholiday weekdays, 5:00 p.m. to 7:00 p.m., during December and January).
- **Seasonal-peak resources—**reduce consumption during the summer months of June, July, and August and during the winter months of December and January in hours on nonholiday weekdays when the real-time system hourly load is equal to or greater than 90% of the most recent "50/50" system peak-load forecast for the applicable summer or winter season.[42]

# Market Oversight and Analysis

ISO New England's market monitoring structure relies on the ISO's Internal Market Monitor and the External Market Monitor, which currently is Potomac Economics. The Internal Market Monitor reports administratively to the company's chief executive officer, whereas both market monitors report functionally to the ISO Board of Directors through its Markets Committee. The Internal Market Monitor seeks input from the EMM to provide another independent review of significant market developments.

This reporting structure is analogous to the oversight structure of internal and external auditors in corporate finance. The functional reporting directly to the Markets Committee of an independent board provides the IMM with the independence vital to its obligation to inform regulators of any significant problems. The administrative reporting to the company's chief executive officer and day-to-day interaction with operational staff prevent the IMM from becoming isolated and support the ISO's responsibility to ensure that the New England markets and prices are transparent and competitive.

This section provides information on the specific role of the market monitoring unit in responding to violations of the market rules.

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[41] ISO New England Inc., *Order No. 745 Compliance Filing*, FERC filing, Docket No. ER11-4336-001 (August 19, 2011), http://www.iso-ne.com/regulatory/ferc/filings/2011/aug/er11_4336-001_prd_filing.pdf.

[42] The 50/50 "reference" case peak loads have a 50% chance of being exceeded because of weather conditions. For the reference case, the summer peak load is expected to occur at a weighted New England-wide temperature of 90.2ºF, and the winter peak load is expected to occur at 7.0ºF. A 90/10 "extreme" case peak load has a 10% chance of being exceeded because of weather. For the extreme case, the summer peak is expected to occur at a temperature of 94.2ºF, and the winter peak is expected to occur at a temperature of 1.6ºF.

## Role of Market Monitoring

Through the following five general monitoring activities, the IMM ensures that prices properly reflect competitive supply and demand conditions and assists FERC in enhancing the competitiveness of wholesale electricity markets for the benefit of consumers:

- Monitoring day-to-day participant behavior and market outcomes
- Mitigating participant behavior found to be anticompetitive as outlined in *Market Rule 1*[43]
- Investigating participant behavior that existing tariff provisions do not explicitly preclude but that may be considered anticompetitive; making a referral to FERC for further analysis and possible sanctions when such behavior or anticompetitive outcomes are identified
- Evaluating and reporting on existing market rules, operating procedures, and market outcomes and making recommendations for improvements
- Evaluating new ISO initiatives and market design proposals to ensure that the revisions will support the efficient operation of competitive wholesale electricity markets

The IMM fulfills these activities by performing the following specific tasks:

- Identifying potential anticompetitive behavior by market participants
- Implementing the mitigation provisions of *Market Rule 1* when appropriate
- Immediately notifying appropriate FERC staff of instances in which the behavior of a market participant may require an investigation and evaluation to determine whether the participant has violated a provision of the ISO tariffs, market-behavior rule, or the *Energy Policy Act of 2005* (EPAct) (see below)[44]
- Providing support to the ISO in administering FERC-approved tariff provisions covering the ISO-administered markets
- Identifying ineffective market rules and tariff provisions and recommending proposed rule and tariff changes that will promote wholesale competition and efficient market behavior
- Providing comprehensive market analysis to evaluate the structural competitiveness of the ISO-administered markets and the resulting prices to identify whether markets are responding to customers' needs for reliable electricity supply at the lowest long-run cost
- Providing regular reports to the ISO's senior management and board of directors and state and federal regulatory agencies that describe and assess the development and performance of wholesale markets, including performance in achieving customer benefits, providing transparency, and meeting federal reporting guidelines
- Evaluating proposed changes in market rules and market design

[43] *Market Rule 1* and appendixes are available at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[44] *Energy Policy Act of 2005*, Pub. L. No.109-58, Title XII, Subtitle B, 119 Stat. 594 (2005) (amending the *Federal Power Act*).

The *Energy Policy Act of 2005* grants FERC broad authority to regulate manipulative or fraudulent behavior in the energy markets. FERC implemented its new authority by amending its existing regulations to prohibit any entity from directly or indirectly engaging in the following behavior in connection with the purchase or sale of electric energy or transmission services subject to its jurisdiction:

- Using or employing any device, scheme, or artifice to defraud
- Making any untrue or misleading statement
- Engaging in any fraudulent or deceptive act, practice, or course of business

These rules are intended to work in conjunction with the enhanced civil penalty authority extended to FERC as a component of EPAct. The Internal Market Monitor is obligated to refer to FERC any finding of a potential violation of EPAct or the market-behavior rules.

## Market Monitoring and Mitigation

As specified in *Market Rule 1*, the IMM monitors the market impact of specific bidding behavior (i.e., offers and bids) and, in specifically defined circumstances, mitigates behavior that interferes with the competitiveness and efficiency of the energy markets and daily reliability payments. Whenever one or more participants' offers or declared generating-unit characteristics exceed specified offer thresholds and market-impact thresholds, or are inconsistent with the behavior of competitive offers, the IMM substitutes a default offer for the offer submitted by the participant. These criteria are applied each day to all participants in constrained areas. A less restrictive set of thresholds is applied each day to systemwide pivotal suppliers.

## ISO *Self-Funding Tariff* and *Open Access Transmission Tariff*

The ISO operates under the *ISO New England Transmission, Markets, and Services Tariff* of which Section II is the *Open Access Transmission Tariff* and Section IV is the *Self-Funding Tariff*.[45] In addition to defining the rules and responsibilities of the ISO and market participants, the tariff outlines various schedules that define the revenues the ISO must collect for its operations and for compensating transmission owners for constructing and maintaining the transmission infrastructure controlled by the ISO. The tariff also defines revenues for providing ancillary services, which are not provided through markets.

The ISO *Self-Funding Tariff* contains rates, charges, terms, and conditions for the functions of the ISO. These services are as follows:

- **Schedule 1: Scheduling, System Control, and Dispatch Service—**scheduling and administering the movement of power through, out of, or within the balancing authority area
- **Schedule 2: Energy Administration Service (EAS)—**charges for services the ISO provides to administer the energy markets
- **Schedule 3: Reliability Administration Service (RAS)—**charges for services the ISO provides to administer the reliability markets

The OATT addresses the collection and distribution of payments for the following transmission services:

[45] These documents are available at http://www.iso-ne.com/regulatory/tariff/index.html and http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

- **Schedule 1: Scheduling, System Control, and Dispatch Service—**involves scheduling and administering the movement of power through, out of, or within the New England Balancing Authority Area.
- **Schedule 2: Reactive Supply and Voltage Control (VAR)—**provides reactive power to maintain transmission voltages within acceptable ranges. Schedule 2 also includes calculations for capacity costs.
- **Schedule 8: Through or Out Service (TOUT)—**includes transactions that go through the New England Balancing Authority Area or originate on a pool transmission facility (PTF) and flow over the PTF before passing out of the New England Balancing Authority Area. Transmission customers pay the PTF rate for the through service or out service reserved for them with respect to these transactions.
- **Schedule 9: Regional Network Service (RNS)—**is an ISO accounting service that allows network customers to efficiently and economically use their resources, internal bilateral transactions, and external transactions to serve their network loads located in the New England area.
- **Schedule 16: System Restoration and Planning Service (Black Start)—**plans for and maintains adequate capability for the restoration of the New England Balancing Authority Area following a blackout.
- **Schedule 19: Special-Constraint Resource (SCR) Service of the *Open Access Transmission Tariff*—**includes the payments and charges for the out-of-merit commitment or operation of resources at the request of transmission owners or distribution companies to manage constraints not reflected in the ISO systems.