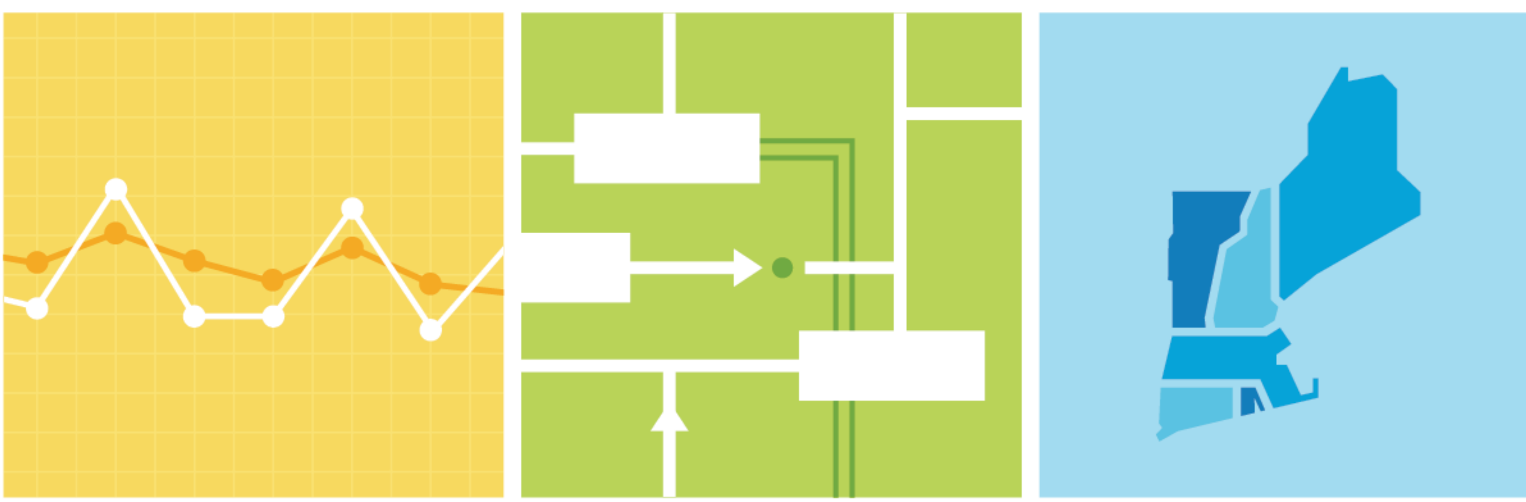
An Overview of New England's Wholesale Electricity Markets

A Market Primer

Internal Market Monitor

MAY 23, 2025



Document Revision History		
Date	**Version**	**Remarks**
5/23/2025	2	Revised report to improve clarity, added DA A/S, and removed the FRM section.

Preface/Disclaimer

The Internal Market Monitor provides this document to enhance participant and stakeholder understanding. Stakeholders should not rely solely on this document for information but should consult the effective Transmission, Markets and Services Tariff ("Tariff") and the relevant Market Manuals, Operating Procedures and Planning Procedures ("Procedures").

In case of a discrepancy between this document and the Tariff or Procedures, the meaning of the Tariff and Procedures shall govern.

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Section 1
Introduction

Over the course of a year, the Internal Market Monitor (IMM) publishes four quarterly reports and an annual report, which provide detailed and comprehensive analyses of New England's wholesale electricity markets. At times, the complexity of these reports can make them challenging to comprehend and some readers may need additional background before approaching them.

This primer aims to bridge that knowledge gap by explaining the fundamentals of the various markets and products covered in those reports. Therefore, whether you are an energy expert or new to the industry, we hope that you find this primer to be valuable resource to support your understanding of New England's wholesale electricity markets.

1.1 Background

As the six states that form New England – Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont – have varying policies, geographies, and resource potential, the generating resources that have developed across the region are varied. However, a common element that affects the entire region is its limited natural resources. Unlike other parts of the country, New England has relatively few indigenous sources of fossil fuels; consequently, the region must import much of its fuel from outside sources.

While a transition to renewable sources of energy production is currently underway in New England, the region still relies on a network of interstate pipelines and liquefied natural gas (LNG) imports to fuel its significant natural gas-fired generation fleet. This reliance on natural gas drives increased electricity costs in the winter when demand for natural gas for use in heating greatly increases, and limited pipeline capacity becomes constrained.

ISO New England (ISO-NE) is the organization charged with designing, administering, and overseeing the wholesale electricity markets in New England. In addition to this critical task, ISO-NE is also charged with planning the region's transmission system and operating the region's power system on a minute-to-minute basis.

1.2 Some Basic Fundamentals

Before continuing, it may be beneficial to some readers if we clarify some of the fundamental concepts that are referenced later in this document.

Market Concepts

There are many types of markets, but at a fundamental level, a market is a place (real or virtual) where parties can gather to facilitate the exchange of goods and services. It is easy to imagine a chaotic street market with many buyers and sellers haggling over the prices of various goods, but in New England, the wholesale electricity markets are coordinated by ISO New England. More specifically, the region's wholesale electricity markets are auction-based markets in which buyers submit competitive bids and sellers submit competitive offers simultaneously. Bids and offers from market participants that were accepted are said to have *cleared* the auction. The price for the good is then set where the highest price that a buyer is willing to pay equals the lowest price that a seller is willing to accept.

Throughout this document, we refer to the market participant who sets the price as *marginal*. In a competitive market, a generator that is marginal is just at the point where the auction-clearing price will cover their incremental cost of production. Other generators with lower production costs receive the same auction-clearing price and are termed *inframarginal;* they receive revenues in excess of their incremental costs. In this way, suppliers are incentivized to reduce their cost of production to widen the spread between what they receive in revenue and what they must pay for production.

The efficiency of a market is measured by assessing the degree to which the market outcome maximizes the *total surplus*, or *total social welfare.* Conceptually, this is the difference between the total value that buyers place on a good and the total cost of producing it. This goal of maximizing social welfare is a typical objective when clearing energy markets.

A competitive market is one in which no supplier or buyer has the ability to unilaterally raise the price of the good. Typically, when we think of markets we assume that as the price of a good rises, buyers will respond by purchasing less of that good. However, energy markets have a fundamental demand-side flaw because there is a lack of demand responsiveness to changes in price.[1] Who looks up the price of electricity before deciding whether to turn on lights, the air conditioner, or other appliances?

With such captive demand that does not respond to increasing prices, it is more likely that suppliers, at times, have *market power,* which is the ability to increase the market price beyond a competitive level by making inflated offers into the market. Think of your car breaking down in a small town with one mechanic; how competitive do you think the repair bill will be? Fortunately, energy market designers have developed screens for market power and mitigation measures that guard against uncompetitive pricing.

While market pricing refers to a pricing method where the price of a good or service is determined by the forces of supply and demand, there are instances when procurement of a good or service may not be suited to market pricing. In these cases, the ISO turns to administrative pricing, which means that prices are set by the ISO rather than by market forces. Typically, the ISO will determine a reasonable rate for the service and participants then decide whether to supply the service for that price. Generally, administrative pricing is used when the properties of a market would appear to fall short of what would be necessary to support competitive outcomes.

Power System Terms

Throughout this text, we use the terms grid, network, and system interchangeably to refer to the New England Bulk Power System, which is a large complex network of power generation facilities and transmission lines that deliver electricity to wholesale customers.

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1 In practice, New England's energy market does have a degree of demand responsiveness that is particularly impactful during stressed system conditions, such as a very hot summer day when air conditioning produces high demand for energy. Demand response resources (DRR) are treated like a supply resource in the markets – like a generator increasing output, demand response is paid for decreasing consumption.

Units

MW and MWh are two different units of measurement used in the context of power and energy. MW stands for megawatt, which is a unit of power that measures the rate of energy transfer or consumption. One megawatt is equal to one million watts, and it is commonly used to express the power output of a generator or the capacity of a power plant.

MWh stands for megawatt-hour, which is a unit of energy that measures the amount of power produced or consumed over a period of one hour at a rate of one megawatt. One megawatt-hour is equal to one million watt-hours, and can serve about 1,000 homes in New England for one hour. It is commonly used to express the amount of electricity generated by a power plant or the amount of electricity consumed over a given period.

In simpler terms, MW is a measure of how much power is being produced or consumed at a given moment, while MWh is a measure of the total energy produced or consumed over a period.

Energy Demand and Load

The terms 'demand' and 'load' are sometimes used interchangeably in our reports. Load is defined as the demand for electricity at any point in time and is typically measured in megawatts (MW) or gigawatts (GW). However, we generally report on load over a specific time period. For example, the average load over an hour would be reported in MWh.

Assets, Units, and Resources

Throughout this text, we may refer to an energy-producing facility as an asset, a unit, or a resource. We sometimes use these terms interchangeably; however, to be precise, each of these labels refers to a different aspect of the electricity generation system.

- **Assets:** An asset is any physical entity that can produce, store, transfer, or consume electricity. Assets in the electricity market can include power plants, wind turbines, solar panels, energy storage systems, and transmission lines. Assets are owned by market participants, such as utilities, independent power producers, or private companies.
- **Units:** A unit refers to a specific generating device that produces electricity from a particular asset. For example, a power plant might have several units, each with its own capacity and characteristics.
- **Resources:** A resource may refer to a combination of one or more assets and units that are grouped together. Resources can be owned by a single entity or by multiple entities that pool their assets together. Resources can include different types of assets, such as a mix of wind turbines and gas-fired power plants.

1.3 ISO-NE Markets

ISO-NE is responsible for designing and administering the wholesale electricity markets in New England. These markets can be broadly categorized into the following four areas, and, in general, this primer is organized to provide an overview of each of these areas.

1. **Energy Markets** – Electric energy is the fundamental product whose production and consumption is coordinated by the ISO through the use of an auction market. Sellers of energy in New England include natural gas-fired generators, hydroelectric plants, and solar power facilities, among others. Meanwhile, the buyers of wholesale energy include investor-owned and municipal utilities, as well as marketing companies that purchase power on behalf of retail buyers.[2] More information about the energy markets can be found in Section 2 and Section 3.

2. **Ancillary Services Markets** – Ancillary services are a group of market services that ensure the reliability of the power system. Many ancillary services, including operating reserves and regulation service, are bought and sold through wholesale market auctions. More information about ancillary services can be found in Section 5, Section 6, Section 7, and Section 8.

3. **Capacity Market** – In addition to administering New England's wholesale markets, ISO-NE performs the critical function of system planning for the region. A key part of this responsibility is ensuring that there is sufficient capacity – that is, the generation (or load-reducing) capability of the region's resources – to meet future demand.[3] ISO-NE runs an auction to procure capacity to meet the resource adequacy objective. More information about the capacity market can be found in Section 9.

4. **Financial Transmission Rights Market** – Buyers and sellers that participate in ISO-NE's energy markets may incur additional costs if the transmission system becomes congested. This market allows participants to purchase a financial product – known as a Financial Transmission Right ("FTR") – that can be used to help manage the costs associated with this congestion. More information about FTRs can be found in Section 10.

Given the diverse objectives of these markets, the market structures and rules that ISO-NE has put in place for each are varied. However, the wholesale electricity markets can generally be classified into one of two market structures:

1. **Forward Market** – a market where the product or service is sold (purchased) in advance of when the product or service is delivered (consumed). Generally speaking, forward markets are often considered *financial* markets as buyers and sellers in these

[2] Power marketing companies buy and sell electricity in wholesale markets. They act as intermediaries between electricity producers, such as power plants, and retail electricity providers, such as utilities, by purchasing large amounts of electricity at wholesale prices and then selling it to retail providers who then distribute it to end-users like homes, businesses, and industries.

[3] Section I of the ISO-NE Tariff defines a resource as a "Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or a Demand Response Resource." https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_1/sect_i.pdf

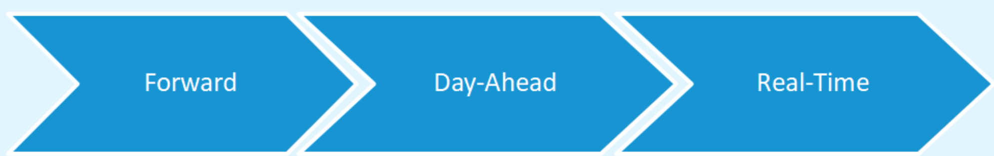
markets are typically taking on financially binding obligations rather than an obligation to physically deliver. Most commonly, buyers and sellers who do not meet their forward market obligations are at risk of financial losses that are based on the replacement price of the product or service. This replacement price is often, but not always, determined in the spot market.

2. **Spot Market** – a market where the product or service is sold (purchased) and the delivery (consumption) occurs immediately. The spot market is often considered a *physical* market because transactions in this market are associated with actual delivery (e.g., flow of power).

An overview of the electricity products bought and sold through New England's forward and spot wholesale markets are summarized in Figure 1-1 below. The different forward markets are operated with different forward time horizons, ranging from over three years (capacity market) to one day (day-ahead energy market) in advance of delivery. Note that while it is theoretically a forward financial market, the day-ahead energy market is a crucial element of the market design in New England and merits its own category. Most energy sales and purchases are made in the day-ahead energy market, and day-ahead cleared energy supply forms the foundation of the next-day physical operating plan.

Despite the day-ahead market being a forward market, this document categorizes the wholesale electricity markets into three groups. This figure is used as a navigation bar throughout the primer as a simple way to help the reader understand the timing of each specific market.

General Categorization of ISO-NE's Wholesale Electricity Markets



Any market that is classified as *forward* is taking place two or more days in advance of delivery, any market classified as *day-ahead* is taking place the day prior to delivery, and any market classified as *real-time* is one where delivery occurs immediately.

Figure 1-1: Spot and Forward Markets

PRODUCT	Time Horizon		
	Forward	Day-Ahead	Spot
ENERGY		Day-Ahead Energy Market	Real-Time Energy Market
CAPACITY	Forward Capacity Market		Performance Payments
ANCILLARY			
Operating Reserves		Day-Ahead Ancillary Services	Real-Time Reserves
Regulation			Regulation Market
Blackstart	Blackstart Procurement		
Voltage			Voltage Support
CONGESTION	Financial Transmission		

The following two subsections provide a high-level overview of the markets for energy and ancillary services products.

1.3.1 Energy Markets

ISO-NE administers its energy markets using both a forward and spot market construct. Market participants can buy and sell energy in the day-ahead energy market based on their expectations for the following operating day. For more information about the day-ahead energy market, see Section 2. Market participants can also buy and sell power in the real-time energy market. This is a spot market that coordinates the production of energy in real time based on actual power system conditions. For more information about the real-time energy market, see Section 3.

1.3.2 Ancillary Services Markets

The ISO procures four main types of ancillary service products. The bullet points below describe the function of each product.

- **Operating reserves** represent additional supply capacity that is available to respond to unexpected contingencies (such as the unexpected loss of a generator or transmission line) during operation of the real-time energy market. Operating reserves are procured both in the real-time market (see Section 6) and in the day-ahead market (see Section 5).

- **Regulation service** is provided by generators or batteries that alter their energy output over very short time intervals (every few seconds) to balance supply and demand in the real-time energy market. Regulation service is procured in real-time only (see Section 7) and has no associated forward market.

- **Voltage support service** helps the ISO maintain an acceptable range of voltage on the transmission system, and is necessary for the reliable flow of electricity. The ISO regulates voltage through reactive power dispatch, and the generators that provide this service receive voltage support payments. [4] This service is not purchased through a market. For more information, see Section 8.

- **Blackstart service** is provided by generators that are able to start quickly without outside electrical supply. The ISO selects and compensates strategically located generators for providing blackstart service. This service is necessary to facilitate power system restoration in the event of a partial or complete system shutdown. This service is not purchased through a market. For more information, see Section 8.

1.3 The Role of the Market Monitors

ISO New England is tasked with the oversight and administration of the wholesale electricity markets in the New England region. These markets operate under a Federal Energy Regulatory Commission (FERC) approved *Tariff* which is a set of rules and regulations that govern the operation of, and participation in, the regional electricity market.[5]

The successful operation of these markets, in terms of their design and market participant conduct, is crucial for ensuring reliability and competitive pricing of wholesale electricity. To monitor and scrutinize the functioning of these markets, ISO New England has two independent market monitors: the Internal Market Monitor (IMM) and the External Market Monitor (EMM). The market monitors evaluate and analyze market outcomes and provide recommendations for market enhancements. In addition to their advisory responsibilities, market monitors are also obligated to report any potential Market Rule violations to the FERC for further investigation.

The mission of the Internal Market Monitor and External Market Monitor is:

1. to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses;
2. to evaluate existing and proposed market rules, tariff provisions and market design elements to identify market design flaws and recommend proposed rule and tariff changes to the ISO;
3. to review and report on the performance of the New England Markets;[6]
4. to identify and notify FERC of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and
5. to carry out the mitigation functions set forth in Appendix A of the Tariff.[7]

[4] The ISO Tariff contains detailed rules regarding compensation for voltage support. See Schedule 2 of Section II: Open Access Transmission Tariff (the OATT), available at: https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf

[5] https://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1

[6] https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor/

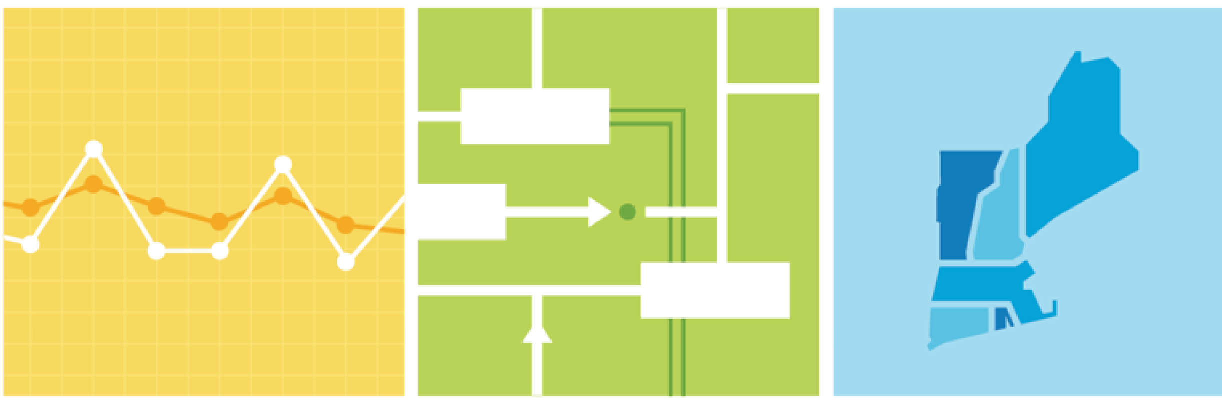
[7] https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

Energy Markets

Section 2: Day-Ahead Energy Market

Section 3: Real-Time Energy Market

Section 4: Closing the Circuit: Real-Time and Day-Ahead Markets



Section 2
Day-Ahead Energy Market

2.1 Introduction

The day-ahead energy market, often referred to simply as the day-ahead market, coordinates the production and consumption of energy one day before the actual operating day.[8] Given that the market clearing takes place in advance of the operating day, the day-ahead energy market is considered a *financial* market. However, there is a link to the real-time energy market (covered in Section 3); the buyers and sellers of energy in the day-ahead market take on financially binding obligations to consume or produce energy in real time. Performing this market clearing in advance of the operating day provides several important benefits, which are enumerated below:

- **Efficient scheduling** – coordinating generators in advance of the upcoming operating day makes it possible to schedule units that require advanced notice to come online. For example, by scheduling these longer-lead time units one day before they are needed, it may be possible to avoid having to rely on fast-start units, which are typically expensive. This allows the ISO to satisfy day-ahead energy demand in the most cost-effective manner.

> The **day-ahead energy market** is a *forward* market that coordinates the production and consumption of energy for the next operating day, and determines energy prices for the forward sale and purchase of energy.

- **Risk management** – the day-ahead market allows participants to lock-in energy prices at the day-ahead price and thereby hedge against real-time prices, which tend to be more volatile. For example, a load-serving entity may wish to limit its exposure to real-time prices by clearing its demand in the day-ahead market. Similarly, a supplier with a gas-fired generator may prefer to sell power day-ahead because receiving an operating schedule before the operating day begins allows it to more effectively manage its fuel supply.

- **Creation of a reliable operating plan** –In its role as a Balancing Authority, the ISO is required to develop an operating plan for each day that meets specific reliability standards and ensures that the system can meet the energy and reserve needs of the region throughout the operating day. The resources cleared in the day-ahead market are relied upon to operate during the operating day, and therefore form the basis for a reliable next-day operating plan.

2.2 Market Clearing

The day-ahead market clearing process takes in a variety of inputs from both participants and the ISO, and uses those inputs to determine which resources will be committed to operate, the

[8] Operating day is defined as "the calendar day period beginning at midnight for which transactions in the New England Markets are scheduled" in Section I of the ISO New Newland Inc. Transmission, Markets, and Services Tariff ("the ISO Tariff"). See https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_1/sect_i.pdf.

output/consumption levels at which supply/demand will clear, and the prices that will be paid to cleared suppliers and charged to cleared demand. We'll discuss each of these concepts in turn.

2.2.1 Day-Ahead Market Inputs

The day-ahead market clearing process begins with numerous inputs sourced from both market participants and the ISO. Participants submit their bids and offers to buy or sell energy, which are due by 10:30 AM Eastern Time (ET) on the day prior to the operating day. Generally speaking, bids and offers are composed of two key components: an offer (or bid) quantity (MWh), and an associated offer (or bid) price ($/MWh). There are several different offer and bid types that participants can use to express their willingness to buy or sell energy in the day-ahead market.

On the *demand* side, participants can submit demand bids in the form of fixed demand, price-sensitive demand, dispatchable asset-related demand (DARD), virtual demand (decrements), or exports. Each of these bid types is shown in Table 2-1 below. Typically, the majority of energy demand that clears in the day-ahead market is bid in as fixed demand, which indicates that the participant is willing to clear (purchase) its bid-in MWh quantity regardless of the market clearing price.

Table 2-1: Demand Bid Types in the Day-Ahead Market

Type	Description
Fixed Demand	A bid to purchase a specified MWh amount at any price. This bid has no associated bid price and will clear regardless of the market clearing price. These must be bid in at the load zone level and are typically associated with physical load.
Price-Sensitive Demand	A bid that includes both a specified MWh quantity and price. The participant is willing to clear this MWh quantity as long as the clearing price is no greater than their specified bid price. These must be bid in at the load zone level and are typically associated with physical load.
Dispatchable Asset-Related Demand (DARD)	DARDs are physical demand that are discretely modeled by the market software. DARDs submit bids to consume energy with one or more segments. Each segment specifies a MWh quantity and a price they are willing to pay for that MWh quantity. DARDs submit additional bid parameters, including min/max consumption levels, ramp rates, maximum daily starts, and others. An example of an DARD is the pumping side of a pumped storage facility.
Virtual Demand ("Decrement")	A virtual bid that is not associated with physical demand. It is a bid to purchase a specified MW amount at a chosen node for no more than the stated bid price. See Section 4.3 for more information on virtual transactions.
Exports	A bid submitted to move energy out of the New England system and into a neighboring system (i.e., New York ISO). These bids must be submitted at external nodes. See Section 4.6 for more information on export transactions.

Participants seeking to offer *supply* into the day-ahead market can submit generator, demand-response resource (DRR), virtual supply (increment), or import offers. Table 2-2 summarizes the different types of day-ahead market supply offers. The vast majority of supply that clears in the day-ahead market is comprised of generator offers. Participants submit generator offers as price and quantity pairs, which express their willingness to supply energy at various levels of energy production. These participants must also provide several other financial and physical parameters associated with their unit; these parameters include costs associated with starting up the unit (start-up cost), costs that do not vary by MW output level (no-load cost), and minimum and maximum operating limits (EcoMin, EcoMax).

Table 2-2: Supply Offer Types for Day-Ahead Market

Type	Description
Generator	An offer submitted by a physical generator in New England to sell energy at its location. A generator submits price and quantity pairs representing the MWh amounts it is willing to supply at certain prices. Generators submit additional parameters, including start-up costs, ramp rates, EcoMin/EcoMax levels, and others.
DRR	An offer submitted by a DRR indicating a willingness to reduce load at its location at a specified offer price. DRRs submit price and quantity pairs representing the MWh amounts by which they are willing to reduce their load at different price levels. DRRs submit additional parameter, including initiation cost, ramp rate, min/max reduction levels, and others.
Virtual Supply ("Increment")	A type of virtual offer that does not represent supply backed by a physical asset. It is an offer to sell a specified MWh amount at a particular node for no less than its stated offer price. See 4.3 for more information on virtual transactions.
Import	An offer submitted to deliver energy into the New England from a neighboring system (i.e., Quebec). These offers must be submitted at external nodes. See Section 4.6 for details on import transactions.

The other critical inputs for the day-ahead market clearing come from the ISO. These include the network model of the region's power system, transmission outage information, reserve requirements, and interface limits.[9] Together these inputs ensure that the day-ahead process will accurately represent the physical characteristics and reliability requirements of the region's high-voltage power system.

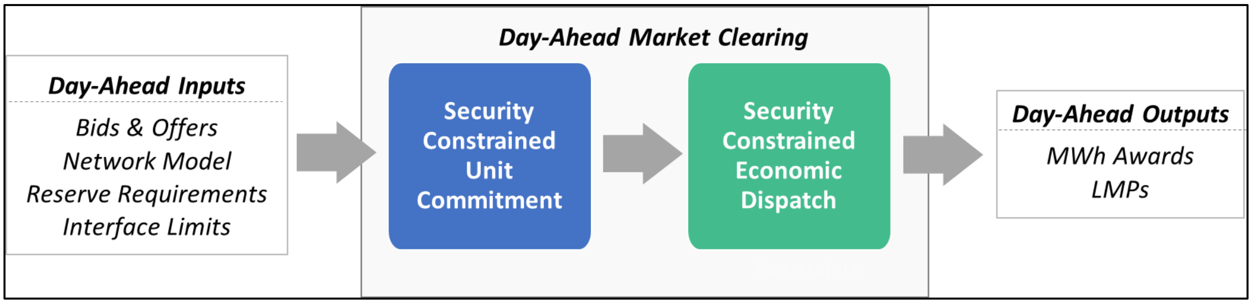
2.2.2 Day-Ahead Market Clearing - Commitment and Dispatch

The ISO uses the inputs discussed above to clear the day-ahead market, determining the most economically efficient set of resources to commit for the next operating day to satisfy bid-in demand. The clearing of the day-ahead market has two sequential steps: unit commitment and economic dispatch.

A simplified overview of the steps required to clear the day-ahead market is provided in Figure 2-1 below.

[9] Real-time reserves and interface limits are discussed in Sections 6.2 and 10.3, respectively. While reserves are not presently priced in the day-ahead market, reserve requirements are considered during the day-ahead unit commitment process.

Figure 2-1: High-level Overview of Day-Ahead Market Clearing Process



The unit commitment process is the first step of clearing the day-ahead market. The unit commitment process determines whether each unit that offers into the day-ahead market will be online or offline during each hour of the operating day. Commitment is simply an on/off decision: a unit is either committed to be online, or it is uncommitted (i.e., it remains offline).

In the unit commitment process, the ISO uses participant-submitted bids and offers as inputs to the market optimization software, which in turn produces commitment decisions for each unit and each hour of the operating day. The unit commitment process will consider the offered costs of resources (e.g., start-up cost, no-load cost, and incremental energy offers) and all physical parameters (e.g., EcoMin/EcoMax, start-up time, minimum down time) of every resource in determining the most efficient set of unit commitments.[10] Participants also have the option to 'self-schedule' their resource, which ensure the resource will be committed and waives consideration of their commitment costs.

The economic dispatch process is the second step of clearing the day-ahead market. The economic dispatch process determines the most efficient output level (or dispatch) of those units that were committed by the unit commitment process. Only those units which are committed in the unit commitment process will then be dispatched in the economic dispatch process, and those units will be dispatched economically (based upon their offered costs) in order to satisfy bid-in demand in a manner that maximizes social welfare (more on this in the next section).

The economic dispatch process produces the two key outputs of the day-ahead market: cleared energy quantities and day-ahead energy clearing prices.

- **Cleared energy quantities** are the amounts of energy, measured in MWh, that a market participant has acquired the obligation to produce (or consume) in each hour of the operating day. For generators and other energy suppliers, the set of cleared energy quantities resulting from the day-ahead market is often referred to as the unit's 'day-ahead energy schedule' or 'day-ahead energy awards.'
- **Day-Ahead energy clearing prices** are the prices paid to suppliers (and charged to demand) for the quantities of energy cleared in the day-ahead market. Day-ahead energy clearing prices are measured in $/MWh, and vary by hour and by location. The

[10] What makes this unit commitment process *security constrained* is that it iterates with a contingency analysis process, which ensures that the system maintains reliability even in the event that a contingency occurs (e.g., the loss of a transmission line or generator).

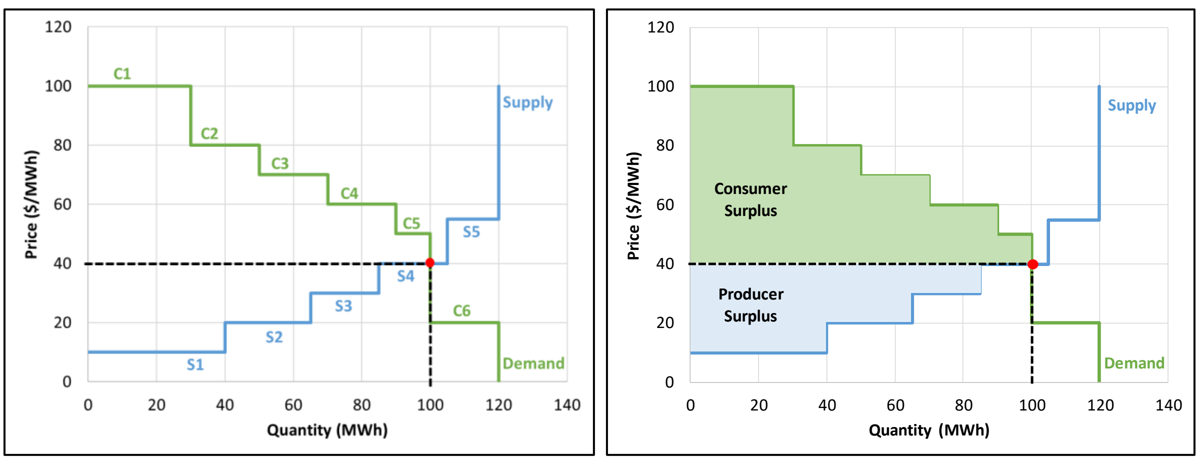
technical term for these energy clearing prices is 'locational marginal prices,' or LMPs. We'll discuss these more in the next section.

2.2.3 Locational Marginal Prices

Locational marginal prices (LMPs) reflect the marginal cost (or value) of energy at a particular location and point in time. Marginal cost pricing—a fundamental principle of economics—ensures that generation and load receive the economically correct price signals that bring about efficient market outcomes. Generally, the LMP is established by the energy offer price of the resource that would be dispatched to serve an additional MWh of energy demand.[11]

A very simple example of the day-ahead energy clearing price being set by the marginal cost of energy supply is illustrated in Figure 2-2 below. The supply curve represents suppliers' marginal costs and the demand curve represents consumers' maximum willingness to pay for energy. The energy clearing price (or LMP) and cleared energy quantity are determined by the intersection of the supply and demand curves: a $40/MWh LMP, and a 100 MWh cleared energy quantity. This clearing price reflects the system marginal cost because the next MWh of energy would be sourced from supplier S4 at a cost of $40/MWh.

Figure 2-2: Marginal Cost Pricing Maximizes Total Social Welfare



Why is this outcome economically efficient? Because it maximizes *total social welfare*, which is the sum of both consumer surplus and producer surplus. This is shown in the right panel of Figure 2-2. Consumer surplus—the area below the demand curve and above the clearing price—represents consumers' net gain; it is the difference between what consumers were willing to pay for energy and what they had to pay (the $40/MWh clearing price). Similarly, producer surplus—the area above the supply curve and below the clearing price—is the net gain for suppliers; it is the difference between the clearing price they received and their marginal cost. The sum of consumer surplus (green area) and producer surplus (blue area) represents total social welfare.

[11] Because there is demand bidding in the day-ahead market, clearing prices may either reflect the marginal benefit of demand when a demand bid sets the price or reflect the marginal cost of supply when a supply offer sets the price.

In this example, total social welfare—the combined green and blue area in Figure 2-2—is maximized when the market clears at exactly 100 MWh.[12] Note this means that consumers C1–C5 take on a financial commitment to consume energy and suppliers S1–S4 take on a financial commitment to provide energy. Had the market cleared at any other point, social welfare would be lower, and the outcome would therefore be inefficient. The $40/MWh LMP is therefore sending the economically correct signals to market participants. At this price, all cleared demand is willing to consume (because the LMP is less than their bid-in willingness to pay), and all cleared suppliers are willing to produce (because the LMP is greater than or equal to their cost of operating), and the socially optimal outcome is achieved.

As its name suggests, the LMP will vary across different locations in the New England power system. Wholesale energy in the region is priced at over a thousand nodes (or pnodes), each of which represents a physical location at which power is injected or withdrawn. For example, every generator modeled by the ISO software has a node where its power output is priced. Nodes are also grouped by geographic area into different zones to create zonal LMPs.[13] The most-commonly referenced LMP for the system is the LMP at the Hub, which is a collection of nodes intended to represent an uncongested price for energy in New England.[14] The Hub LMP is generally used as the pricing location for New England power derivative contracts traded in the financial markets.

The LMP at each location is the sum of three components: energy, congestion, and loss (Figure 2-3). The energy component represents the incremental cost to deliver energy to the "reference point" on the system.[15] The energy component of the LMP is the same across all locations at any given point in time and can be thought of being fundamentally driven by overall supply and demand dynamics in the market. Our simple example above, which illustrates how the day-ahead market could produce a $40/MWh LMP, reflects only this energy component.

[12] To see why the 100 MWh outcome maximizes total social welfare, consider the following: if 1 more MWh were to clear, this would cost $40 (the marginal cost of S4) but yield a benefit of only $20 (the marginal value for C6); alternatively, if 1 less MWh were to clear, this would save $40 (marginal cost of S4) but forgo a benefit of $50 (the marginal value for C5).

[13] Zonal LMPs are the load-weighted average price of each node in the zone. Zones can be for load zones or demand response resource (DRR) aggregation zones. As of November 1, 2022, there were eight load zones (e.g., Vermont) and 20 DRR aggregation zones. There is also pricing at external nodes, which are discussed in Section 7.

[14] The Hub LMP is the simple average of the LMPs at the nodes that make up the Hub. As of December 31, 2022, the Hub consists of 32 nodes. See https://www.iso-ne.com/static-assets/documents/2021/07/hub_definition.pdf and Section III.2.8 of Market Rule 1 for more information.

[15] The reference point is not a single location but rather the load-weighted average of all nodal prices. In practice, the energy component is equal to the shadow value of the energy balance constraint modeled in the day-ahead optimization software.

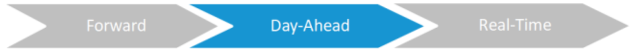
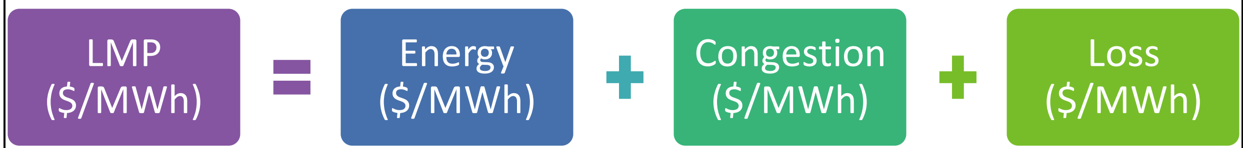


Figure 2-3: Components of the LMP



When the transmission system is uncongested, the LMPs at every node are nearly identical (ignoring the loss component for now). However, if power flows on a transmission line reach the maximum capability of that element, then the system becomes congested and LMPs will be different across locations. This difference in the LMPs across the system is reflected in the congestion component; it is the marginal cost of congestion at a given node relative to the system's reference point.[16] (See Section 10 for further details on transmission congestion.)

The last part of the LMP is the loss component, which reflects the cost of losses at a given location relative to the reference point. As power flows along the transmission system, some amount of energy is lost in the form of heat (i.e., resistive losses). Because of these losses, generators must produce slightly more energy than load consumes in order to ensure energy demand is satisfied. The loss component, which is typically a very small part of the total LMP, captures the incremental cost associated with the power losses that result from delivering an additional MWh to a location.[17]

[16] In practice, the congestion component is determined by shift factors (i.e., how flows on each line change in response to a change in power injections at a node) and the shadow price of each binding constraint (i.e., the change in the objective function value when this constraint is relaxed by 1 MW).

[17] For details on the loss component calculation, see https://www.iso-ne.com/static-assets/documents/support/faq/lmp/loss_component_lmp_faq.pdf

Section 3
Real-Time Energy Market

3.1 Introduction

The real-time energy market coordinates the production of energy in real time based on actual power system conditions (i.e., actual real-time load, real-time generator availability, etc.). Whereas the day-ahead energy market is a *financial* market that prepares the power system for the following operating day (covered in Section 2), the real-time market is a *physical* market, whose transactions correspond to actual flows of power in real time. Several important aspects of the real-time energy market are discussed below.

> The **real-time energy market** is a *spot* market that coordinates energy production and determines prices based on actual power system conditions.

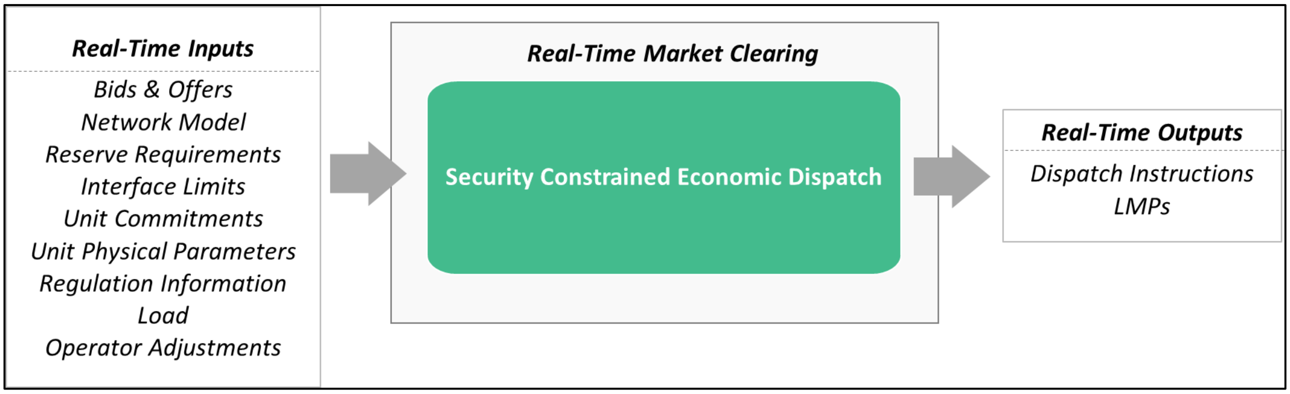
- **Efficient energy dispatch** – A resource's costs to produce energy in real-time can differ from its costs in the day-ahead energy market. For example, a natural gas-fired generator may face a higher price to procure gas in real-time than it would in the day-ahead timeframe. The real-time energy market dispatches all resources in a least-cost manner, taking into consideration the most up-to-date operating costs. This can result in resources being dispatched in real-time at output levels that differ from their day-ahead awards.

- **Balancing market –** Unanticipated events, such as warmer-than-expected weather or forced equipment outages, can cause system energy needs to change from the prior day's expectations. The real-time energy market is considered a *balancing* market as it plays an essential role in adjusting market participants' schedules to ensure there is sufficient generation to match actual system needs. An important aspect of New England's energy market design is the two-settlement construct in which participants are only exposed to the real-time price for the real-time energy quantity that deviates from their day-ahead market schedules.

- **Maintain reserve capability** – Reserves ensure there is enough fast-starting or fast-ramping supply capability available – over and above load requirements – for the system to recover quickly from an unexpected event like the loss of a large generator or transmission line. The real-time energy market dispatches supply resources to serve real-time load *while also* maintaining sufficient additional supply capability in "reserve" to meet reliability needs. The real-time reserve market is discussed in more detail in Section 6.

The high-level objective of the real-time market is to satisfy load (both 'firm' and price sensitive) and meet reserve requirements in the most cost-effective manner. The real-time market clearing process requires inputs from both market participants and the ISO. Real-time inputs and outputs are summarized in Figure 3-1 below.

Figure 3-1: Real-Time Market Process



It is worth highlighting at the outset several key ways in which the real-time energy market differs from the day-ahead energy market.

- **Demand participation**. The day-ahead market clears suppliers to satisfy bid-in demand, and load serving participants must actively express their willingness to pay for day-ahead energy to the ISO via a day-ahead demand bid. The same is not true for the real-time market; the majority of load does not actively participate in the real-time market, and will consume energy regardless of the wholesale energy price.
- **Time granularity**. The day-ahead market clears supply and demand on an hourly basis. The real-time market is sub-hourly, and resources will receive dispatch signals that change during an hour as load changes.
- **Look-ahead**. The day-ahead market dispatches resources from one hour to the next, and consequently has a 'look-ahead' period of one hour. The real-time market has a much shorter look-ahead period. In real-time, the ISO calculates dispatch signals that indicate the output levels at which resources should be operating 10-15 minutes in the future.

3.2 Real-Time Unit Commitment

Recall that unit commitment is simply the decision to turn on, or commit, a resource. In real-time, the resources that were committed in the day-ahead market form the basis of the real-time operating plan. The ISO may also commit resources in real-time. There are three distinct processes that allow for commitment of resources in real-time. Two of these processes can commit resources that are able to start up quickly, while the third can commit resources that have longer lead times.

- **Real-Time Unit Commitment (RTUC).**[18] A software process called real-time unit commitment (RTUC) makes commitment recommendations for fast-start resources.[19] RTUC is executed every 15 minutes and looks 90 minutes to four hours ahead into the future, and recommends fast-start resources for commitment and shut-down. ISO

[18] Control Room Operating Procedure (CROP) 35005 details resource commitment in the RTUC process: https://www.iso-ne.com/static-assets/documents/2014/12/crop_35005.pdf

[19] Fast-start resources are those which can come online and synchronize to the grid in 30 minutes or less, and which have a minimum run time and minimum down time of one hour or less.

system operators review these recommendations, and use them to inform decisions about fast-start unit commitment.

- **Contingency Dispatch Scheduling, Pricing, and Dispatch (CD-SPD)**. CD-SPD is a special version of the ISO's normal dispatch software that is run infrequently and only in emergency conditions. CD-SPD can commit and dispatch fast-start resources.
- **Security Constrained Reserve Adequacy (SCRA)**.[20] SCRA is run multiple times per day, and looks out from the present moment through the end of the operating day. SCRA can commit non-fast start resources (those with longer lead times) if it determines that such resources are needed to meet projected load and reserve requirements later in the day.

3.3 Real-Time Market Clearing

The software that clears the real-time market is called the Unit Dispatch Software, or UDS. UDS, which is generally executed every ten minutes, dispatches all committed resources in a least-cost manner to satisfy real-time load. The desired dispatch points (DDPs) calculated by UDS are sent electronically to resources throughout New England, and represent the power output level (measured in MW) at which the resource should operate. Upon receiving a new DDP, resources are expected to move to it as quickly as possible. DDPs are one key output of the real-time market.

Real-time energy prices are a second key output of the real-time market. Just as in the day-ahead market, real-time energy prices are determined using marginal cost pricing principles, can vary by location, and have three components (energy, congestion, and losses). Real-time prices, however, are produced every five minutes.

The following sections address the bids and offers, unit physical parameters, load, and operator actions that feed into this market clearing process. Reserve requirements, interface limits, and regulation information are discussed in Section 6.2, Section 10.3, and Section 7, respectively.

3.3.1 Real-time Market Offer and Bid Types

The real-time market is a physical market, so participants cannot submit offers or bids without corresponding energy supply or consumption. Because the real-time market does not accommodate purely financial transactions, there are fewer offer and bid types in the real-time market than in the day-ahead market.

On the *demand* side of the market, participants can submit bids for asset-related demand and exports. The vast majority of load in real-time, however, is not bid into the market by participants; it is simply consumed with no sensitivity to price.

[20] The following System Operating Procedure (SOP) details the Security Constrained Reserve Adequacy (SCRA) process. Typically, the SCRA process runs about four times during the operating day. https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/sysop/rt_mkts/sop_rtmkts_0050_0010.pdf

Table 3-1 below summarizes the types of real-time demand.

Table 3-1: Demand Types for Real-Time Market

Type	Description	Dispatching/Scheduling
Load	Load is non-dispatchable electricity consumption, and does not respond to price. Load is ultimately settled based on metered consumption at the nodal level.	Not dispatched or scheduled by the ISO.
Asset-Related Demand (ARD)	Assets within New England that consume energy based on bids submitted to the ISO. Examples include pumped storage hydro resources and grid-connected batteries.	Receives DDPs within feasible operating range.
Export	Exports are bids to move energy from New England into a neighboring control area (i.e., New York) See Section 4.6 for more information on exports and external transactions.	Exports do not receive DDPs. They are instead 'scheduled' on an hourly or 15-minute basis (depending on location). Priced exports are scheduled based upon the export bid price relative to the expected energy price for the scheduling interval Fixed exports are scheduled regardless of price.

On the *supply* side of the real-time energy market, participants can submit generation, demand response resources (DRRs), and import offers.

Table 3-2 below summarizes real-time supply types.

Table 3-2: Supply Offer Types for Real-Time Market

Type	Description	Dispatching/Scheduling
Generator	Physical generation. Generators submit offers to supply energy with segments specifying a MW amount and price reflecting their willingness to produce energy. Generators submit several other parameters, including start-up costs, ramp rates, and EcoMin/EcoMax levels.	Receives DDPs within feasible operating range.
DRR	Dispatchable load reduction. Demand response resources (DRRs) submit offers to reduce their load with segments specifying a MW amount and price reflecting their willingness to consume less energy. DRRs submit other parameters, including initiation cost, ramp rate, and min/max reduction levels.	Receives DDPs within feasible operating range.
Import	Imports are offers to move energy into the New England system from a neighboring control area. See Section 4.6 for details on imports and external transactions.	Imports do not receive DDPs. They are instead 'scheduled' on an hourly or 15-minute basis (depending on location). Priced imports are scheduled based upon the import offer price relative the expected energy price for the scheduling interval. Fixed imports are scheduled regardless of price.

Each generator, DARD, or DRR unit has a feasible dispatch range based on their current output and their physical parameters offered into the market. The key parameters that determine a resource's dispatch range are its minimum operating level (EcoMin for generators), its maximum operating level (EcoMax for generators) and ramp rate (the rate, in MW/min, that the resource can move within the range between EcoMin and EcoMax). A simple example of a dispatchable resources' feasible output range is shown in Figure 3-2 below. The black line shows full capability (0 to EcoMax), the orange line represents physical dispatch range, the yellow line is the feasible ramp range, and the green line is the economic dispatch range. [21]

Figure 3-2: Physical Parameter Impact on Dispatchable Range

The ISO can dispatch each unit within its constrained operating range (green line), based on its offer price. Figure 3-2 shows a unit limited by its ramp-down limit in the lower direction and its EcoMax in the positive direction. For many generators (i.e., those with stored or pipeline fuel supplies), these parameters are relatively static from day to day. However, intermittent renewable resources do not have static EcoMax parameters because their fuel source (i.e., wind, water, and sun) varies throughout the day. Such resources typically update their EcoMax parameter frequently throughout an operating day, in order to reflect expected physical capability. Although these units cannot be dispatched in the upward direction, the ISO can dispatch them down from their maximum output. In New England, Do-Not-Exceed (DNE) dispatch rules allow the ISO to dispatch these resources in a similar manner to other resources, using forecasts of maximum output as their upper operating limit.

3.3.2 Fast-Start Pricing Mechanics and Implications for Price Formation

Real-time pricing mechanics are similar to day-ahead pricing mechanics, as discussed in Section 2.2.3. However, differences between day ahead and real time exist. In the day-ahead market, one single process (security constrained economic dispatch) determines both cleared energy quantities and energy clearing prices. In real-time, however, dispatch and pricing are separated into two separate and distinct processes. These processes are separated in order to facilitate an element of the market design called *fast-start pricing.* The purpose of fast-start pricing is to better reflect the operating costs of fast, flexible resources in real-time market clearing prices.

Fast-start units present a unique issue in pricing calculations because many have no dispatchable operating range; they must either be offline, or online and dispatched at their EcoMax. Such resources are commonly described as being 'lumpy.' As discussed in Section 2.2.3, energy prices are determined in part by the offer cost of the marginal resource that would be

[21] The ramp-up limit exceeds the EcoMax in this example for illustration purposes. The ramp range exceeds the EcoMax to show that the unit is limited by their EcoMax, not their ramp rates. In reality, units do not have ramp rates that apply above their EcoMax.

dispatched to serve an additional MW of energy demand. Because of their lumpiness, fast start resources are rarely on the margin for energy. As such (and without fast-start pricing logic), these resources would rarely be able to set the price of energy. This has two negative effects: energy prices do not transparently reflect the costs of operating these resources, and the resources may require out-of-market payments to recoup operating costs.

The fast start pricing logic addresses this issue by performing dispatch and pricing separately.

- The *dispatch* process respects all resources' operational constraints (including fast-start resources) when determining least-cost dispatch instructions. In the dispatch process, fast-start resources remain 'lumpy.' This process determines the DDPs sent to all resources.
- The *pricing* process, however, treats fast-start resources as able to be dispatched between 0 MW and EcoMax, thereby eliminating their lumpiness. This allows fast-start resources to be on the margin for energy more frequently, and consequently they can set price in more circumstances. Additionally, fast-start commitment costs (start-up and no-load costs) are amortized to per-MW values and added to energy offers. This process determines the energy clearing prices.

The end result of the fast start pricing logic is that resources continue to receive physically feasible DDPs (from the dispatch process), while the resulting clearing prices are more reflective of the costs to commit and operate fast-start resources (from the pricing process).

3.4 Operator Actions and Control Room Operating Procedures

Real-time conditions can pose challenges to the reliable operation of the system, especially when conditions are abnormal. At times, control room operators will take manual or out-of-market actions to ensure reliability. These actions are governed by a detailed set of operating procedures, which are published to help ensure transparency to market participants. Real-time market energy needs may differ from those expected in the day-ahead timeframe for several reasons, including unplanned generator and transmission outages, load forecast error, and changes in imports and exports with neighboring control areas. Operators have tools at their disposal to respond to real-time conditions that the market software cannot account for.

It is important that market monitors assess out-of-market actions, as they can have significant market impacts and sometimes distort outcomes and market efficiency. When operators perform out-of-market actions they may affect energy prices as well as other market outcomes that are discussed in later sections of this document (ancillary service prices, NCPC payments, pay-for-performance payments in the Forward Capacity Market, etc.). Further, out-of-market actions could be symptomatic of market software limitations, missing market products, or gaps in market design, and therefore monitoring is essential in order to identify areas for future enhancements.

The following bullet points describe the most common manual interventions that operators may take in the real-time market. These actions occur with varying levels of frequency and impact.

- **Cuts to real-time only external transactions**[22]**:** Operators can reduce real-time export transactions down to the day-ahead net interchange value if necessary. Reducing exports increases the amount of power within the New-England system.

- **Use of short-term emergency line ratings**[23]**:** Operators can change power line ratings, which may impact reserve requirements in local reserve zones. Based on operating procedures, there are normal and emergency line ratings. Normal line ratings maintain a higher level of reliability, while emergency ratings provide operators with more flexibility.

- **Posturing**[24]: Posturing limits the output of certain generators to ensure that their fuel is available in the event of a system contingency. Such generators provides operating reserves (back up generation that can be dispatched in the event of a contingency) instead of energy while postured, and are available for manual dispatch above the posturing level in the event of a system contingency.

- **Supplemental commitments**[25]**:** As noted above, the SCRA process may result in additional resource commitments in order to meet projected load and reserve requirements. Such supplemental commitments are termed 'capacity' commitments. In addition, supplemental commitments can be made to support another specific reliability need, such as local second contingency protection or voltage support. These sorts of reliability commitments are generally made based on unit-specific attributes (physical location, reactive power capability, etc.) and may not incorporate economic considerations.

- **Manual fast-start resource commitments**[26]**:** Operators perform this action to bring additional fast-start generators or DRRs online quickly. Unlike the action above, this does not go through the SCRA process.

- **Manual generator dispatch:** The operators can manually provide DDPs to generators that differ from those that would be produced by the market clearing software. Generally, such an action is taken when operators can see a potential issue (i.e., a reserve shortage) that may occur beyond the look-ahead period of the market clearing engine, and which therefore cannot be addressed by the market clearing engine. For example, operators may manually dispatch generators with slower ramp rates up all the way to economic maximum. This causes faster ramping generators to be backed down, so that they are providing less energy but more reserves, allowing a potential reserve shortage to be avoided.

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[22] Control Room Operating Procedure, CROP .31002 Curtailing External Transactions outlines real-time only export cuts: https://www.iso-ne.com/static-assets/documents/2015/12/crop_31002.pdf

[23] For more information, see ISO New England Operating Procedure No. 19 - Transmission Operations: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op19/op19_rto_final.pdf

[24] Control Room Operating Procedure, CROP.25001 Posturing, outlines the ISO's posturing procedures. It is available at: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/sysop/cr_ops/crop_25001.pdf

[25] The following procedure (SOP-RTMKTS.0050.0005 - Determine Reliability Commitment for Real-Time) contains additional details about reliability commitments:

https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/sysop/rt_mkts/sop_rtmkts_0050_0005.pdf

[26] Control Room Operating Procedure CROP.25007 Manual Dispatch describes the Fast Start Manual Dispatch process that brings additional fast start resources online: https://www.iso-ne.com/static-assets/documents/2015/11/crop.25007.pdf

- **Fast Start Reliability (FSR) Flag**: Operators can use the fast start reliability (FSR) flag to prevent the software from sending shutdown instructions to online fast-start generators.

- **Reserve bias**: The operator can manually increase the system operating reserve requirements by applying a 'bias', or multiplier, in order to procure additional reserves.

- **Load Adjustment Factor**: The Load Adjustment Factor (LAF) is a positive or negative MW deviation value added to the short-term load forecast. Operators may apply LAFs when the software is not accurately reflecting real-time balances between supply and demand, which can occur due to Area Control Error (ACE), generator ramping, and instantaneous changes in load.

Section 4
Closing the Circuit: Real-Time and Day-Ahead Markets

4.1 Introduction

In the preceding sections, we provided separate explanations for the day-ahead and real-time energy markets. Nevertheless, these markets are fundamentally interrelated, and therefore, this section explains some important aspects of their interplay. In addition, to avoid duplication, we will also discuss certain aspects that are common to both markets.

4.2 Price Convergence

Price convergence – that is, how similar the prices are between the day-ahead and real-time energy markets – is an important concept within ISO-NE's two-settlement wholesale energy market design as it provides insight into how well the day-ahead market is anticipating real-time conditions.[27] The objective of the real-time energy market is to provide least-cost dispatch while meeting load and reliability requirements. The day-ahead energy market serves an important role in achieving this ultimate goal because it can help produce a least-cost schedule that reliably meets expected load in advance of real time.

Scheduling generators in the day-ahead market is advantageous because it allows for more flexibility in generator selection. After the day-ahead market closes and as the real-time market approaches, the number of generators the ISO can commit and dispatch shrinks. This is because longer-lead time generators, which may require several hours to start up, often cannot be dispatched in response to sudden or transient supply needs in the real-time market. Thus, in real time, there is a greater reliance on fast-start generators, which are often more expensive.

We can consider an example to see how price convergence serves as a signal that the day-ahead market is accurately anticipating real-time conditions. Consider a day where real-time load exceeds the day-ahead cleared demand. To satisfy this increase in load, the ISO would need to commit additional (and often more expensive) fast-start generators in real time. The resulting real-time price would be greater than (sometimes much greater than) the day-ahead price. On the other hand, if participants expected high real-time load, they clear more demand in the day-ahead market, resulting in a high day-ahead price. If real-time load was then much lower than expected, committed resources would be dispatched down, lowering the price, and no expensive fast-start commitments would be required.

A well-functioning energy market does not require day-ahead and real-time prices to be equal all the time. Rather, it requires that the day-ahead clearing reflect an unbiased expectation of the real-time conditions, given the information available. This, in turn, results in day-ahead prices that represent an unbiased expectation of real-time prices. Of course, despite efforts to anticipate real-time conditions in the day-ahead market, real-time conditions frequently differ from day-ahead expectations. This leads to price differences.

Ultimately, energy supply, energy demand, and reliability actions taken by the ISO determine day-ahead and real-time prices. Thus, when day-ahead and real-time prices vary, it is often the

[27] Virtual transactions play an important role in price convergence. This topic is discussed in Section 4.3.

result of shifts in supply and demand conditions. For example, if a generator clears an energy supply offer in the day-ahead market but experiences an unplanned outage in real-time, the available system supply falls and real-time prices will likely rise. In another example, higher-than expected temperatures on a summer day can translate to greater real-time loads and higher real-time prices than those observed in the day-ahead market.

In addition to unforeseen changes between day-ahead and real-time conditions, market participants may prefer transacting energy in one market over another. For example, a supplier with a gas-fired generator may prefer to sell power in the day-ahead market because receiving an operating schedule the day before expected physical delivery allows the supplier to better manage its natural gas purchase and delivery for the following day. Similarly, a load-serving entity may want to limit its exposure to more volatile real-time prices by purchasing load in the day-ahead market. While most load and generation clear in the day-ahead market, some participants might have a preference for the real-time market. For example, intermittent generators may prefer to clear in the real-time market when the environmental factors that influence their ability to generate are more certain.

4.3 Virtual Participation and its Role in Price Convergence

Virtual transactions may only be submitted in the day-ahead energy market and, if cleared, become non-physical supply or demand positions; they do not materialize as physical consumption or delivery in real time.

There are two types of virtual transactions in New England's day-ahead energy market:

1. **Virtual demand bid**: known as a decrement bid, or DEC, this is a demand bid that is not associated with physical load. This type of virtual transaction clears when the associated bid price is *greater* than the LMP for the location where the bid was made.

2. **Virtual supply offer**: known as an increment offer, or INC, this is a supply offer that is not backed by a physical asset. This type of virtual transaction clears when the associated offer price is *less* than the LMP for the location where the offer was made.

Virtual bids and offers can be submitted at any pricing location on the system during any hour. Virtual transactions clear in the day-ahead market like other demand bids and supply offers (see Section 2 for more information). The ISO settles virtual transactions based on the quantity of cleared virtual energy and the difference between the hourly day-ahead and real-time LMPs at the location. Cleared *virtual supply* offers make a profit if the day-ahead price is greater than the real-time price (sell high, buy back low), and cleared *virtual demand* bids make a profit if the day-ahead price is less than the real-time price (buy low, sell back high). See Section 4.4 on settlement mechanics for further details.

The participation of virtual transactions provides the market with various benefits.

- improving price convergence between the day-ahead and real-time markets (discussed below),
- mitigating both buyer-side and seller-side market power through increased levels of competition,
- increasing the liquidity of the day-ahead market, which allows more participants to take forward positions in the energy market, and

- hedging the price risks associated with delivering or purchasing energy in the real-time energy market.

While market participants submit virtual demand bids and virtual supply offers to profit from differences between day-ahead and real-time LMPs, they can also help improve price convergence (a concept discussed in Section 4.2 above).[28] Generally, profitable virtual transactions help to more efficiently commit generation in the day-ahead market so that it better aligns with real-time needs. This brings prices across the two markets closer together. To see this, we consider two examples.

In the first example, over-commitment of physical generation in the day-ahead market leads to systematically *higher* day-ahead prices absent virtual transactions. In this case, market participants can offer virtual supply at lower prices than physical generation, consequently displacing some of it. The cheaper cleared virtual supply offers drive the day-ahead price downward toward the real-time price. As long as the real-time price is lower than the day-ahead price, the virtual supply profits (ignoring transaction charges and other costs).

In the second example, under-commitment of physical generation in the day-ahead market leads to systematically *lower* day-ahead prices. In this case, market participants can offer virtual demand at higher prices than physical demand, and more expensive supply must be committed to meet the additional demand. This drives the day-ahead price higher and more in line with the real-time price. As long as the real-time price is higher than the day-ahead price, the virtual demand profits (ignoring charges and other costs).

4.4 Settlement Mechanics

ISO New England uses a two-settlement construct to calculate charges and credits for Market Participants in the day-ahead and real-time energy markets. In the first settlement, a participant is paid (or charged) for energy produced (or consumed) in the day-ahead market at the day-ahead LMP. In the second settlement, the participant is then paid or charged for any real-time deviations from their day-ahead positions at the real-time LMP.

Clearing a demand bid or a supply offer in the day-ahead market results in an initial settlement. This day-ahead settlement calculation is straightforward: cleared MWh quantities are multiplied by day-ahead LMPs to determine each participant's credits or charges. This calculation is performed for each cleared supply offer and cleared demand bid at each location and for every hour.

A simple example of credit and charge calculations for one hour of the day-ahead market is shown in Table 4-1 below. A credit represents a payment made to a participant and is a positive value, while a charge is the amount a participant owes and is a negative value. By ISO convention, demand quantities are represented by negative values and supply quantities are positive. This participant has a variety of cleared bids and offers in the day-ahead market in this example hour.

[28] In fact, virtual transactions are referred to as convergence bids in some wholesale energy markets.

Table 4-1: Day-Ahead Settlement Credits and Charges Example

Asset or Activity	Location	Day-Ahead Cleared (MWh)	Day-Ahead LMP ($/MWh)	Day-Ahead Credit / Charge (+/-)
LSE Demand Bid	NEMA Load Zone	-100	$50	-$5,000
Decrement Bid	Node LD.PLEASNT23	-50	$48	-$2,400
DARD[29] Bid	Node AR.ABCARDP	-150	$48	-$7,200
Gen Offer	Node UN.ABCGEN1	200	$47	$9,400
Import Offer	Node .I.ROSETON 345 1	100	$45	$3,375
			Total Day-Ahead Energy Settlement:	**-$1,825**

Consider the first row of the table above. The participant has cleared a demand bid of -100 MWh at a day-ahead LMP of $50/MWh and it will incur a charge (-100 MWh x $50/MWh = -$5,000). This participant has locked in an energy price of $50/MWh for the 100 MWh that it cleared. If the real-time LMP turns out to be much higher, then this participant will have effectively shielded (hedged) its real-time energy consumption from the higher real-time price. Note that this hedges the participant's price risk but not necessarily its volume risk. If the participant ends up with real-time load in this hour that exceeds 100 MWh, then it will have to purchase that additional energy at the real-time price.

The energy that flows in the real-time market results in the second settlement (i.e., the real-time settlement). The real-time settlement calculations apply to deviations from day-ahead positions. In each interval, the difference between real-time metered energy quantities and day-ahead cleared energy positions for every transaction (e.g., metered generation or virtual transaction), are multiplied by real-time LMPs to determine each participant's credits and charges.[30]

Table 4-2 shows a simple example of calculations of credits and charges for the real-time market.[31] Credits represent payments made to participants and have positive values, and charges are the amounts participants owe and are negative.

[29] Dispatchable asset-related demand (DARD).

[30] In practice, the real-time settlements are done at the five-minute level rather than the hourly level.

[31] For simplicity of the examples, we assume that real-time prices and quantities are consistent across a full hour.

Table 4-2: Real-Time Settlement Credits and Charges Example

Asset or Activity	Location	Day-Ahead Cleared (MWh)	Real-Time Delivered (MWh)	Real-Time Deviation (MWh)	Real-Time LMP ($/MWh)	Real-Time Credit/Charge (+/-)
LSE Demand Bid	NEMA Load Zone	-100	-125	-25	$48	-$1,200
Decrement Bid	Node LD.PLEASNT23	-50	0	50	$40	$2,000
DARD Bid	Node AR.ABCARDP	-150	-125	25	$40	$1,000
Gen Offer	Node UN.ABCGEN1	200	150	-50	$40	-$2,000
Import Offer	Node .I.ROSETON 345 1	100	100	0	$39	$0
					Total Real-Time Energy Settlement:	**-$200**

Examine, for example, the first row of this table. This participant has a cleared demand bid of 100 MWh in the day-ahead market, but consumed 25 additional MWh of metered load in the real-time market. For this additional consumption, it will incur a *charge* of $1,200. This participant had locked-in the day-ahead LMP for the 100 MWh of demand that it cleared day-ahead. Because the participant ended up having real-time load greater than 100 MWh in this interval, it had to purchase the additional energy at the real-time price.

The net settlement across both markets for this LSE Demand Bid is the sum of the credits/charges for the day-ahead position and the credit/charge for the real-time position, or a charge of $6,200 (-$5,000 + (-$1,200)). Across all positions, this participant receives a charge of $2,025 for this hour; a charge of $1,825 from the day-ahead market, and an additional charge of $200 from the real-time market.

4.5 Net Commitment Period Compensation Payments (Uplift)

Uplift is an out-of-market, make-whole payment made to suppliers when their as-offered production costs, as well as certain types of opportunity costs, are not fully recovered through the market clearing prices. This revenue adequacy mechanism ensures that suppliers are not made financially worse off by following ISO clearing or dispatch instructions. In the ISO-NE Tariff, the term for uplift is "Net Commitment Period Compensation", or NCPC; but we use the terms "uplift" and "NCPC" interchangeably in this document.

To understand why uplift payments arise, it is helpful to briefly review the marginal pricing logic discussed in Section 2.2.3. Recall that the market-clearing price (LMP) is determined by the marginal dispatch cost of the unit needed to meet the next increment of load, and this price is paid to suppliers cleared or dispatched to produce energy. Importantly, this pricing mechanism can result in a revenue shortfall for generators, particularly those that have high commitment costs, since these costs are not reflected in LMP calculations (except through the fast start pricing mechanism discussed earlier in Section 3.3.2).

Units that are committed and dispatched by the ISO are eligible for uplift payments if their energy revenue is insufficient to cover their production costs. Some resources may be committed by the market clearing software to cost-effectively satisfy the system load and reserve requirements, but operate at a loss. Additionally, resources may be committed to satisfy a particular reliability need (e.g., local reserve zone needs, voltage support, etc.) and may operate out-of-rate and require uplift payments as a result.

The "no-worse off" principle underpins the design of uplift payments. This principle ensures that suppliers have incentive to follow ISO instructions even when such instructions are not profitable, because uplift credits ensure that their total compensation is equal to their next-best alternative (i.e., remaining offline). Without this compensation, generators may be financially motivated to either shut down or reduce their output if they are operating at a loss, rather than following ISO instructions.

There are two categories of uplift payments:

- **Recovery of as-offered production costs:** This category of uplift payments is designed to compensate generators for the costs in their supply offer to produce energy (i.e., start-up, no-load, and incremental energy costs). By compensating generators for these costs, they are incentivized to operate even if they receive revenue (the LMP) that is less than their costs.

- **Recovery of lost opportunity costs:** This category of uplift payments is designed to compensate suppliers for lost profit opportunities when they are dispatched by the ISO in such a manner that they incur an opportunity cost. This can occur for a variety of reasons, including fast-start pricing mechanics, timing issues between posted prices and dispatch instructions, or ISO out-of-market actions. A simple example of an opportunity cost occurs when the ISO dispatches a resource down when the price of energy is high (i.e., above its marginal cost of production). In such a case, the resource incurs an opportunity cost, because it would prefer to produce energy rather than follow ISO dispatch.

NCPC is paid in both the day-ahead and real-time energy markets. Day-ahead NCPC payments are relatively straightforward and ensure participants will not lose money by following ISO-instructed day-ahead schedules. In the real-time market, NCPC payments cover a much broader range of costs, notably opportunity costs, which arise only in the 5-minute spot market. Table 4-3 below summarizes the categories of NCPC associated with recovery of production costs.

Table 4-3: Reasons for Production Cost-related NCPC Credits

Reason	Reason Description	Market
Economic	Commitment and dispatch to meeting the system load and reserve requirements.	Day-ahead and Real-time.
Local Second Contingency	Commitments providing local second contingency protection in import-constrained areas.	Day-ahead and Real-time.
Voltage	Commitments providing voltage control in specific locations.	Day-ahead and Real-time.
Distribution Reliability	Commitments providing support to local distribution networks, also known as special constraint resource (SCR) payments.	Real-time only.
Generator Performance Audit	Commitments to satisfy the ISO's performance auditing requirements, including for dual fuel generators testing on oil.	Real-time only.

Within the above categories of NCPC, there are further subtypes of payments, which generally align with the recovery of the commitment and dispatch components of production costs, and with drivers of opportunity costs. The subtypes are summarized in Table 4-4 below.

Table 4-4: NCPC Types

NCPC Type	Type Description	Market	Reason(s)
Commitment Out-of-Merit	*Production cost* based payments provided to cover commitment costs not recovered through LMP.	Day-Ahead and Real-time	Economic, Local Second Contingency, Voltage, Distribution Reliability, Generator Performance Audit
Dispatch Out-of-Merit	*Production cost* based payments provided to a resource dispatched above their economic dispatch point to cover the portion of as-offered costs not recovered through the LMP.	Real-Time only	Economic, Local Second Contingency, Voltage, Distribution Reliability, Generator Performance Audit
External	*Production costs* based payments made to external transactions that are cleared out-of-rate.	Day-Ahead and Real-time	Economic
Rapid Response Pricing Opportunity Cost	*Opportunity cost* based payments provided to a resource dispatched below their economic dispatch point when fast-start pricing results in higher LMPs.	Real-Time only	Opportunity cost
Dispatch Lost Opportunity Cost	*Opportunity cost* based payments provided to a resource that is instructed by the ISO to run at levels below its economic dispatch point due to timing differences between dispatch instruction and LMPs.	Real-Time only	Opportunity cost
Posturing	*Opportunity cost* based payments provided to a resource that is dispatched down from the resource's economically dispatch point for reserve or fuel rationing.	Real-Time only	Opportunity cost

4.6 Imports and Exports: External Transactions

External transactions are energy market transactions that allow market participants to transfer power between New England and neighboring control areas, and represent an important part of the overall supply and demand picture.[32]

Market participants use external transactions for a variety of reasons. For example, market participants could use external transactions to fulfill contractual obligations to buy or sell power between two control areas (e.g., a power purchase agreement) or to import renewable energy and collect environmental credits.[33] Additionally, transferring power between different control areas can help reduce total production costs across control areas by allowing power to flow from lower priced to higher priced control areas. External transactions can also provide reliability benefits to the interconnected systems.

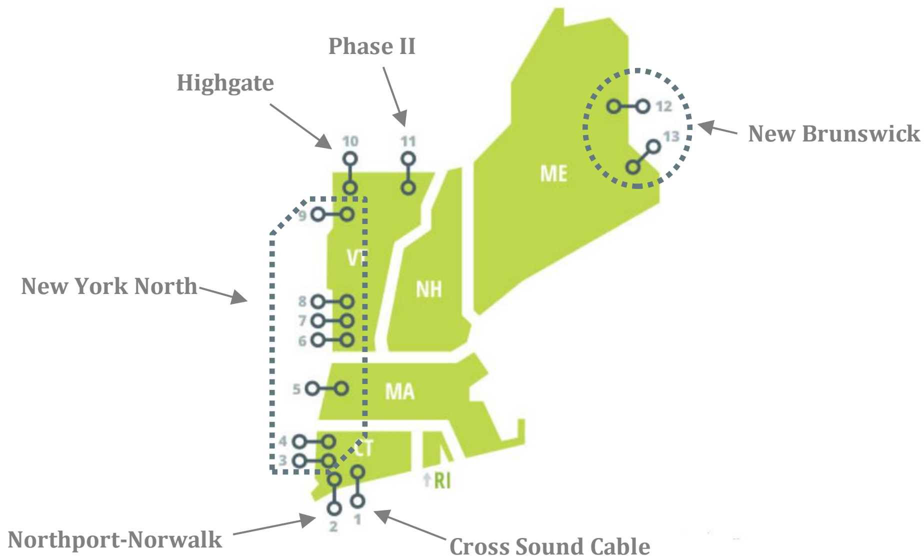
[32] A control area, or balancing authority area, is an area comprising a collection of generation, transmission and load within metered boundaries for which a responsible entity (defined by NERC to be a balancing authority) integrates resource plans for that area, maintains the area's load-resource balance, and supports the area's interconnection frequency in real time.

[33] A Renewable Energy Certificate (REC) represents an amount of energy generated by a renewable energy source. These certificates can be bought by energy providers for the purposes of satisfying their Renewable Portfolio Standard. The generator selling these certificates must produce the amount of energy associated with their purchased RECs.

4.6.1 Interconnections with New York and Canada

New England is electrically interconnected with three different control areas: New York, New Brunswick and Hydro-Québec. A collection of 13 different transmission lines connects New England with the three neighboring control areas. The connecting transmission lines with the three neighboring control areas are shown in Figure 4-1 below.

Figure 4-1: New England Interconnection with Neighboring Control Areas



The power that flows between New England and these three control areas occurs over six separate external interfaces.[34] Participants that want to import, export, or wheel power through New England must engage in external transactions over these interfaces.[35]

As can be seen in Figure 4-1, New England's border with New York is made up of three external interfaces:

1. **New York North (lines 3-9)**: an interface comprised of seven alternating current lines that carry power between New York and western New England.
2. **Cross Sound Cable (line 1)**: a direct current line running between Connecticut and Long Island, New York.
3. **Northport-Norwalk Cable (line 2)**: an alternating current line running between Connecticut and Long Island, New York.

Figure 4-1 also shows the three interconnections with Canada:

[34] An external interface represents an individual transmission line, or a group of transmission lines, that interconnects New England with another control area. Power flows over the individual line(s) that comprise each external interface are jointly monitored for reliability purposes.

[35] A wheeled, or wheel-through, transaction is when power flows from one control area to a different control area, with the power flowing through one or more "third party" control areas. For example, a participant may want to flow power from New York to New Brunswick. This would require the participant to clear an import transaction into New England from New York and a corresponding export transaction from New England to New Brunswick.

1. **Phase II (line 11)**: a direct current line running between New England and the Hydro-Québec control area.
2. **Highgate (line 10)**: a direct current line running between New England and the Hydro-Québec control area.
3. **New Brunswick (lines 12-13)**: comprised of two high-voltage alternating current lines running between New England and the New Brunswick control area.

The six external interfaces allow power to flow between the neighboring control areas but only up to a certain operational limit, known as the Total Transfer Capability (TTC) rating. New England's six external nodes are listed in Table 4-5 below, along with the commonly used external interface names.

Table 4-5: Import and Export Capabilities

Neighboring area	Interface name	External node name	Import capability (MW)	Export capability (MW)
New York	New York North	.I.ROSETON 345 1	1,400 - 1,600	1,200
New York	Northport-Norwalk Cable	.I.NRTHPORT138 5	200	200
New York	Cross Sound Cable	.I.SHOREHAM138 99	346	330
Hydro Québec (Canada)	Phase II	.I.HQ_P1_P2345 5	2,000	1,200
Hydro Québec (Canada)	Highgate	.I.HQHIGATE 120 2	225	170
New Brunswick (Canada)	New Brunswick	.I.SALBRYNB345 1	1,000	550
Total			**5,171 – 5,371**	**3,650**

Each interface has a different TTC, and the values can be different for import and export capabilities at the same interface due to reliability needs. For example, the New York North interface typically has a higher import capability into New England than its export capability out of New England. TTCs frequently vary depending on system conditions, including weather, transmission outages and contingencies.

4.6.2 Bidding and Scheduling

External transactions clear in the day-ahead and real-time markets independently. However, a cleared day-ahead transaction can carry over to real time if the participant elects to also submit the transaction in real time. Alternatively, the participant may choose to offer the transaction only in real time. External transactions in the day-ahead and real-time energy markets are discussed in further detail below.

Day-ahead Market

In the day-ahead market, external transactions establish financial obligations to buy or sell energy at external interfaces. Day-ahead external transactions do not represent the physical flow of power and no coordination exists with neighboring control areas when clearing day-ahead transactions. Like all other day-ahead supply and demand transactions, all external transactions in the day-ahead market are cleared for whole-hour periods based on price (i.e., lower priced imports and higher priced exports clear first) while respecting physical constraints – the interface TTCs. In the day-ahead market, participants can submit three different types of external transactions:

1. **Fixed**: these transactions are offers to import energy, or bids to export energy, at any price.

2. **Priced**: these transactions include an offer or bid price, representing either the maximum a participant is willing to pay in order to purchase energy for export to another control area, or the minimum price a participant requires in order import energy into New England.

3. **Up-to-congestion (UTC)**[36]: these transactions create simultaneous load and generation obligations where one of those obligations is at an external node. These transactions clear based on the congestion and loss differences between the LMPs of the two nodes. For example, a participant submitting a UTC transaction may offer an import transaction over the New York North interface and bid to serve load in the Connecticut load zone. The transaction will clear if the price difference (i.e., cost of congestion) between the New York North pricing node and the Connecticut load zone is less than the offered price spread they are willing to pay.

While the day-ahead market is a financial market, cleared day-ahead external transactions receive scheduling preference in the real-time market.[37]

Real-time Market

Unlike the day-ahead market, scheduled real-time transactions define the physical flow of energy that will occur between control areas. In addition to import and export transactions, participants may also wheel energy through New England, flowing between two external interfaces (e.g., New Brunswick to Cross Sound Cable). Wheel-through transactions are evaluated as fixed transactions and flow unless there is a transfer constraint.[38]

ISO-NE operators coordinate real-time tie flows with neighboring balancing authorities based on joint acknowledgement that the transactions have been scheduled in each area and can be accommodated under operational criteria. At all external interfaces other than New York North, the scheduling process occurs 45 minutes prior to the start of each hour, and a transaction that is scheduled will flow during that entire hour. Importantly, real-time external transactions are not 'dispatchable' in the same sense as supply resources like generators and DRRs, or demand resources like DARDs. External transactions do not receive DDPs from the ISO, and will not be dispatched up or down in the same manner as these other resource types. Rather, an external transaction that is scheduled for an hour will flow at the scheduled MW value during that hour, unless reliability events require that it be curtailed Priced transactions are scheduled based on price forecasts for the that hour. For example, if the price forecast for the hour is $40/MWh, and an import has offered a price of $35/MWh, that import will be scheduled for the hour.

[36] An up-to-congestion transaction creates both a load and generation obligation. For example, a cleared up-to-congestion transaction may involve offering the supply of power into New England through an external interface, and a simultaneous transactions serving load into New England at a pricing node within New England.

[37] For more information on the scheduling of external transactions, see Section III.1.10.7 of the ISO New England Tariff.

[38] A "wheeled" transaction occurs when an external transaction flows power through New England into a different neighboring area. The transaction requires matching import and export transactions to flow power through New England.

At the New York North interface, the real-time scheduling process occurs more frequently, and relies on a process known as Coordinated Transaction Scheduling (which is discussed next).

4.6.3 Coordinated Transaction Scheduling

Coordinated transaction scheduling (CTS) is administered jointly by ISO-NE and the New York Independent System Operator (NYISO) for *real-time* flows across the New York North interface, which is also known as “Roseton” or the “NYISO-ISONE” interface in New York.

CTS is designed to improve the real-time power flow between New England and New York. More specifically, CTS facilitates the flow of power from the lower-cost region to the higher-cost region, better converging prices between the control areas and reducing overall production costs. To accomplish these goals, at a high level, the interface bid and offer scheduling and settlement process for New York North has the following features:[39]

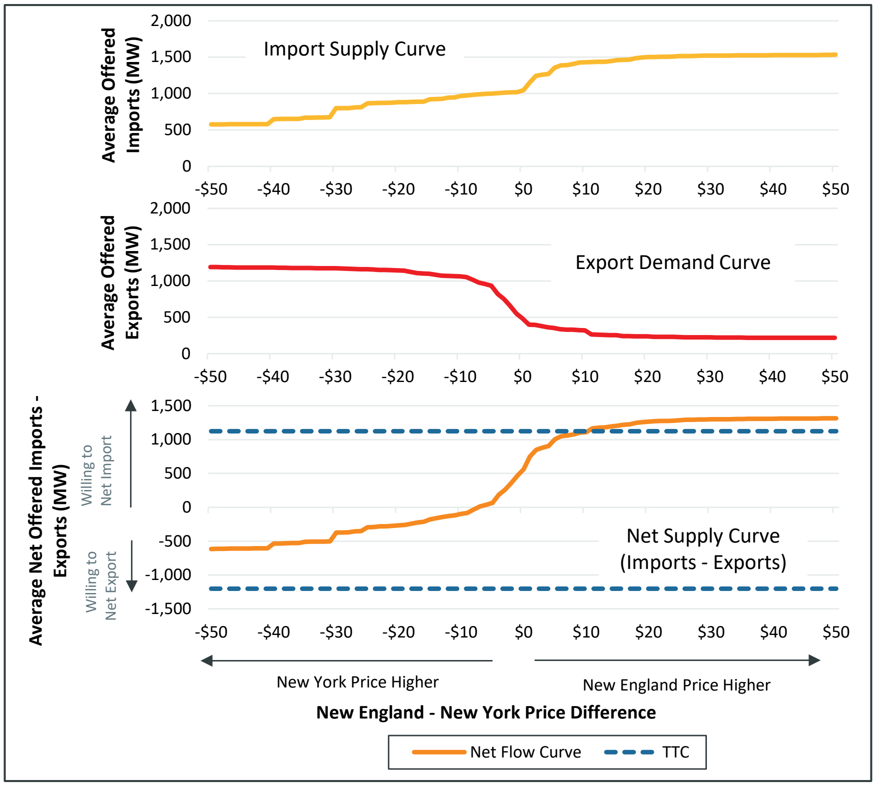
- a unified bid submission and clearing process,
- a scheduling duration of 15 minutes (rather than 1 hour),
- bid submittal and clearing timelines closer to the interval when power flows,
- a spread bid offer format, and
- no fees on transactions.

CTS requires participants to submit interface bids to schedule power. An interface bid specifies the bid quantity (MW), the direction of flow (to New York, or to New England), and the minimum expected price spread that the participant is willing to accept. Bid prices can be positive, negative, or zero. A positive bid price indicates the participant is willing to trade power when the forecasted price in the source market is lower than the price in the destination market (buy low and sell high) by at least the amount of the bid price. A negative bid price indicates a willingness to counterintuitively buy high and sell low; i.e., to trade power when the energy price is expected to be higher at the source than the destination, up to the negative bid price.

[39] External bids and offers are “scheduled” to flow based on forecasted prices over a pre-specified time period (under CTS schedules are set in 15-minute blocks).

Figure 4-2 below shows an example of how total submitted CTS bids and offers are aggregated and cleared. The curves are based on actual transactions and are indicative of generally observed activity.

Figure 4-2: CTS Supply and Demand Curves



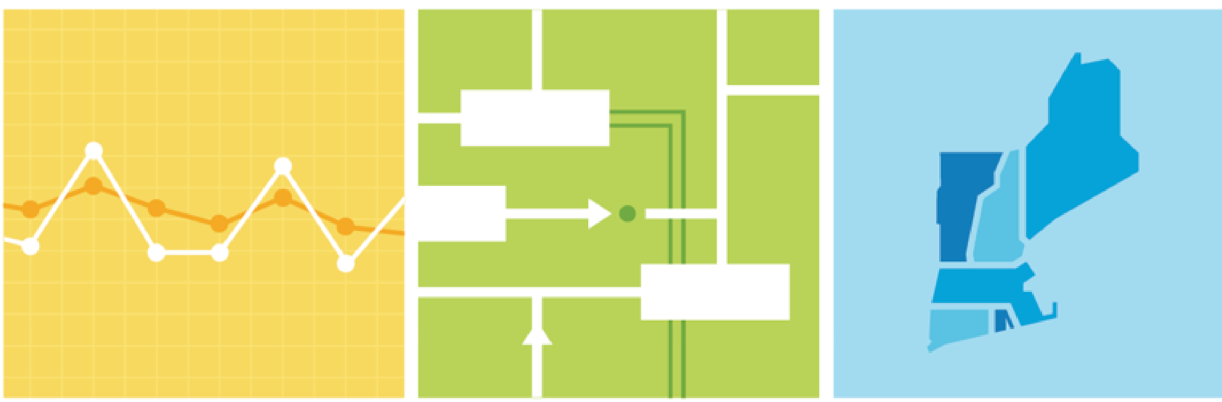
The import supply curve shows offered imports, or CTS spread transactions in the New England direction. As the New England – New York price spread increases, more imports are willing to clear. When New England and New York prices are equal ($0/MWh spread), 1,000 MW of imports are willing to clear. The export demand curve shows the offered exports, or CTS spread transactions in the New York direction. As the New England – New York price spread increases (higher NE prices), fewer exports are willing to clear because they become increasingly less profitable.

The net supply curve shows the net of the import and export curves. The net flow that can clear is limited by the TTC. In this particular example, if the New England forecasted price is more than $10/MWh higher than the New York forecasted price, no additional external transactions will clear as the import TTC limit is reached and the price will be set by a $10/MWh spread bid. This is illustrated by the fact that the net supply curve (orange line) exceeds the import TTC (top dashed line) at the price of $10/MWh.

CTS is a joint process with New York ISO, and CTS transactions are not scheduled with the real-time market software that generates DDPs and LMPs (just like non-CTS transactions). Rather, NYISO produces CTS schedules before real-time DDPs are produced, based on price forecasts from each ISO. Price forecasts are calculated for each 15-minute interval and are used to determine the expected price differences between the regions, which participant bids clear, and the net interface flow. ISO-NE creates its supply curve data (the basis of its CTS price forecast) using current offers and system conditions 45 minutes ahead of the scheduling interval. The NYISO forecasts price 30 minutes ahead of the scheduling interval.

Due to this time lag and forecast error, as well as participant bids, CTS schedules are not always economic after energy prices are determined. However, unlike the other New England interfaces, participants assume the risks of forecast error; there is no NCPC paid to transactions clearing out-of-merit.

Ancillary Services Markets



Section 5
Day-Ahead Ancillary Services

5.1 Introduction

Day-Ahead Ancillary Services (DA A/S) enable the co-optimization of the scheduling of energy and reliability services in the Day-Ahead Market. Market participants can offer to provide both energy and a range of reserve products that help the system respond to changing system conditions. These reserve products are an essential part of the day-ahead scheduling process because they help ensure that ISO New England has enough resources committed to manage forecasted system needs for the next operating day.

DA A/S is a market enhancement introduced on February 28, 2025, that integrates the procurement of ancillary services into the **day-ahead market**. These ancillary services are critical to ensuring that ISO-NE has resources available to satisfy the load forecast, and also to respond to unexpected events, such as the sudden loss of a generator or a sharp change in demand.

The implementation of DA A/S marked an important improvement in how New England's electricity markets secure the services needed to reliably operate the region's power system. DA A/S brings two key reliability requirements into the DAM: the load forecast, and operating reserve requirements. DA A/S was developed in response to several emerging challenges in the region's energy system, in particular:

Growing Dependence on Variable Energy Resources

The addition of more renewable energy, such as wind and solar, introduces greater variability and makes it harder to forecast supply and demand. Because these resources are weather-dependent, system operators need access to flexible resources that can quickly respond when conditions change. This increases the importance of scheduling reserves that are capable of covering both expected and unexpected system needs.

Limitations of the Forward Reserve Market

Prior to DA A/S, ISO New England relied on the Forward Reserve Market (FRM) to procure certain reserves. However, the FRM operated separately from the energy market and procured only a subset of required operating reserves in only certain on-peak hours. This created a gap between forward procurement of reserves and the actual system needs that arise in real time.

- DA A/S was introduced to address these challenges by bringing reserve procurement directly into the Day-Ahead Market. Through co-optimization, the market schedules energy and reserves together, allowing the prices for both products to reflect the true costs of providing these services.
- DA A/S fully reflects the key requirements for a reliable day-ahead operating plan: physical supply to satisfy the load forecast, and fast-ramping capability to satisfy all operating reserve requirements.

5.2 Products

The Day-Ahead Market procures four types of reserve services:

- **Flexible Response Services (FRS)**: A suite of services analogous to real-time reserves, including Day-Ahead TMSR, TMNSR, and TMOR, representing fast-start or fast-ramping capabilities to aid in recovery from the loss of large transmission or generation facilities.
    - **Ten-Minute Spinning Reserve (TMSR):** Reserves provided by resources that are already online and synchronized to the power grid, capable of supplying energy within ten minutes if needed.
    - **Ten-Minute Non-Spinning Reserve (TMNSR):** – Reserves provided by resources that are not currently synchronized to the grid but can start and supply energy within ten minutes.
    - **Thirty-Minute Operating Reserve (TMOR):** – Reserves provided by resources that can supply energy within thirty minutes to help the system recover from larger or longer-lasting events.
- **Energy Imbalance Reserve (EIR):** A product that allows ISO New England to call on resources to operate above their day-ahead energy schedule within sixty minutes to bridge gaps between day-ahead cleared supply and forecasted demand.

These reserve services are scheduled alongside energy through a co-optimized market clearing process. Resources that are scheduled to provide these services receive compensation for being available and are incentivized to supply energy if called upon in real time. This process ensures that both energy and reserves are secured through a competitive market that reflects the relative costs and capabilities of available resources. It also provides market participants with clear price signals that reflect the value of providing flexibility and reliability to the power system.

5.3 Co-Optimization and Pricing Mechanisms

DA A/S extends ISO-NE's unit commitment and economic dispatch algorithms to co-optimize energy and reserves. DA A/S also adds reliability constraints to align day-ahead reserve procurement with real-time reliability standards:

Flexible Response Services (FRS) Constraints:

- Ten-Minute Spinning Reserve: Requires online resources that can provide energy within 10 minutes. This constraint is satisfied by TMSR awards.
- Ten-Minute Non-Spinning Reserve: Requires resources that can start and provide energy within 10 minutes. This constraint is satisfied by TMSR and TMNSR awards.
- Thirty-Minute Operating Reserve: Two constraints that require resources that can provide energy within 30 minutes. These constraints are satisfied by TMSR, TMNSR, and TMOR awards.
    - Minimum Total Reserve Requirement: Ensures a baseline level of reserves is maintained.
    - Total Reserve Requirement: Ensures the sum of all reserves meets system needs.

Forecast Energy Requirement (FER) Constraint:

- Ensures that the total cleared day-ahead physical energy supply and Energy Imbalance Reserve (EIR) meet or exceed the ISO's forecasted load for each hour.
- This constraint addresses the "energy gap" that can occur when the day-ahead market clears less physical energy than the forecasted load, by procuring a combination of additional energy and EIR to bridge this gap.

Market participants submit supply offers for both energy and ancillary services. The outcome from the clearing engine is a unified set of prices reflecting the marginal value of each product at each location and time:

- Locational Marginal Prices (LMPs) – for energy, varying by location and hour.
- Day-Ahead Ancillary Service Clearing Prices (DA A/S CPs) – for each reserve product, there is one system-level reserve price in each hour.
- Forecast Energy Requirement Price (FERP) –for meeting the forecast energy constraint.

All forms of supply that help to satisfy the FER constraint are paid the FER Price. This means that resources cleared to provide physical DA energy are paid the FER Price, in addition to the DA LMP. EIR awards also receive the FER Price. This dual-pricing mechanism internalizes the marginal cost of procuring physical supply capability to meet expected load.

5.4 Settlement

Call-Option Construct

The DA A/S market uses a two-part call-option settlement design to settle ancillary services awards. This settlement design provides resources with compensation for their contribution to meeting the ISO's reliability needs, while also providing financial consequences if resources are unable to perform if called upon in real-time. If the LMP is higher in real-time than was expected, resources that do not operate must cover the replacement cost of their energy.

When participants are developing offers for the DA A/S products they should consider the **strike price** for each relevant hour on the following day. The strike price is an expectation of the RT Hub LMP in that hour plus a $10 adder. In real-time, if the Hub LMP meets or exceeds that strike price then the resource will face a close-out charge which they can offset by running and providing energy.

The settlement process for DA A/S can be summarized as follows:

1. **Cleared Day-Ahead Quantity**

- A participant submits offers to provide ancillary services (EIR, TMSR, TMNSR, TMOR).
- The DA market co-optimizes and clears a quantity of each service from each resource based on price and constraints.

2. **DA A/S Payments**

- For each cleared MW of ancillary service:

DA A/S Payment = Cleared MW × Day-Ahead AS Clearing Price

- Each product has its own clearing price, based on marginal opportunity cost of providing that service.

3. **Real-Time Close-out**

Participants that clear a day-ahead ancillary service product may also be subject to a **close-out charge** in addition to receiving a credit. This charge applies only when the real-time Hub LMP exceeds the strike price. If the real-time price is below the strike price, no close-out charge is assessed.

The charge is calculated separately for each DA A/S product as follows:

Close-out Charge = Awarded MW × max(RT Hub LMP−Strike Price, 0)

This mechanism ensures that participants face appropriate financial consequences for failing to perform, while allowing them to earn revenues when they meet their obligations.

Section 6
Real-Time Reserve Market

6.1 Introduction

Bulk power systems need reserve capability to be able to respond to a contingency; that is, an unexpected loss of a large generator or transmission line. Reserve capability – that is, the ability of an asset to provide additional energy from an offline or online state in thirty minutes or less – can be quickly converted into energy to replace such an unexpected loss. Sudden and unexpected losses of energy supply can also negatively affect the synchronous eastern interconnection due to inadvertent power flows and cascading losses in other control areas.

> The **real-time reserve market** is a *spot* market that procures operating reserve capability through a co-optimized process in the real-time energy market.

In New England, there are three distinct reserve requirements determined by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council Inc. (NPCC). Requirements are based on the magnitude of the largest contingency and second largest contingency on the system at a given point in time. Examples of such large contingencies in New England include the DC tie line to Hydro-Quebec and nuclear power generators. The ISO also carries a 30-minute replacement reserve meant to restore reserves after the initial loss of a contingency.

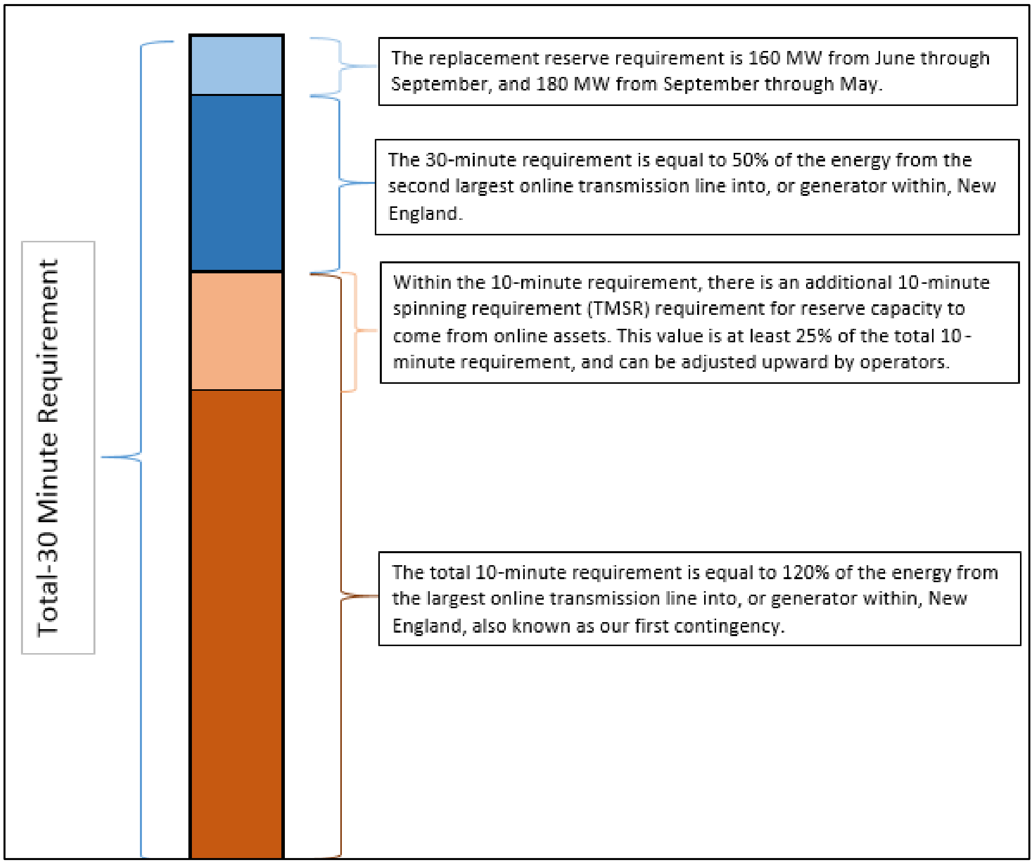
In order to meet these requirements, the ISO procures three reserve products associated with varying physical characteristics to respond to a contingency loss. These reserve products are procured from assets based upon their ability to produce energy within:

- 10 minutes from an online state,
- 10 minutes from an offline state, and
- 30 minutes from an offline or online state.

6.2 Requirements

System-level reserve requirements are based on the size of the system's two largest contingencies, additional criteria determined by the NPCC, and any operator adjustments made during the operating day to maintain system reliability (discussed in Section 3.4). The sum of all reserve requirements is known as the total 30-minute requirement. Each of the components is color coded and described in Figure 6-1 below.

Figure 6-1: Breakdown of Total-30 Minute Requirement



In addition to system reserve requirements, there are local thirty-minute reserve requirements in three import-constrained zones: Connecticut (CT), Southwest Connecticut (SWCT), and NEMA/Boston. Similar to system reserve requirements, local reserve requirements are based on the largest loss (generator or transmission) in the import-constrained zone.

6.3 Products

In order to satisfy reserve requirements, the ISO procures and prices three reserve products. Each reserve product can contribute to satisfying one or more of the reserve requirements. The three reserve products are:

- **Ten-minute spinning reserve (TMSR):** supplied by online resources capable of converting capacity to energy within 10 minutes.
  - TMSR can contribute to satisfying the TMSR, total 10-minute reserve, and total 30-minute reserve requirements (both system-level and zonal).
- **Ten-minute non-spinning reserve (TMNSR):** supplied by offline resources that can start and synchronize to the grid within 10 minutes.
  - TMNSR can contribute to satisfying the total 10-minute and total 30-minute reserve requirements (both system-level and zonal).
- **Thirty-minute operating reserve (TMOR):** supplied by online resources that can increase output within 30 minutes or offline resources that can start up and synchronize within 30 minutes.

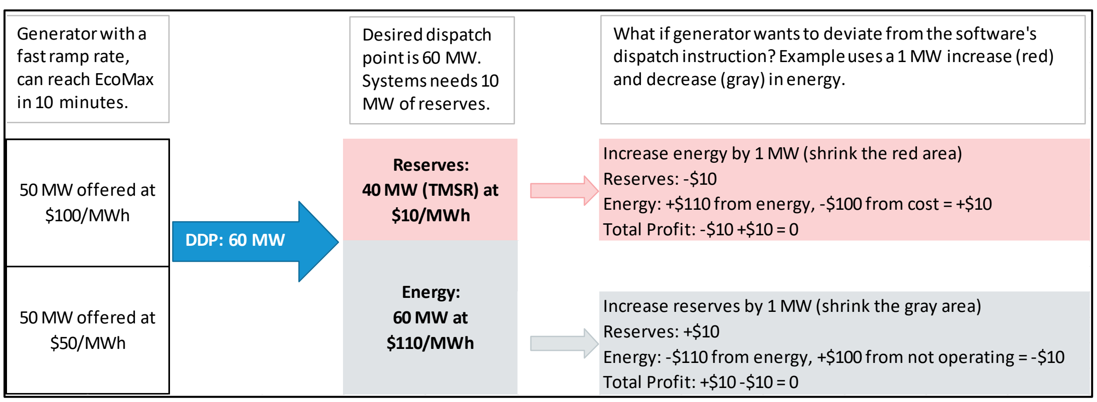
- TMOR can contribute to satisfying only the 30-minute reserve requirements (both system-level and zonal).

6.4 Dispatch and Pricing

Operating reserves are procured in real time through a dispatch and pricing process that co-optimizes energy and reserves. The market dispatch and pricing software determines real-time reserve quantities and the prices for each reserve product. Participants do not submit offer prices to provide reserves in the real-time market. As a result, reserve clearing prices are opportunity-cost based, and ensure that a resource is financially indifferent between providing energy and reserves. In other words, when a generator is instructed to a lower dispatch level to provide reserves rather than energy, it is compensated through reserve clearing prices for any opportunity cost it may incur as a result of not producing energy at a high LMP.

A reserve price greater than zero occurs when the dispatch software must dispatch down one or more resources that are in-merit to provide energy in order to create additional reserves and satisfy the reserve requirement. The resulting reserve price ensures that these re-dispatched resources are indifferent between providing reserves and providing energy. This provides appropriate price signals to generators providing energy and reserves that ensure resources have incentive to follow the ISO's dispatch instructions. Figure 6-2 below shows an example of how the dispatch software re-dispatches resources to optimize both energy and reserves.

Figure 6-2: Example of Pricing of Re-Dispatch for Reserves



In the example above, the 100 MW generator offers 50 MW at $50/MWh, and an additional 50 MW at $100/MWh. Another resource (not shown), with an energy supply offer of $110/MWh, is marginal for energy and sets the real-time LMP equal to $110/MWh. Without reserves, the generator would be expected to clear all 100 MW at an LMP of $110/MWh. However, the center boxes show the resource was dispatched to provide 40 MW of TMSR at a reserve price of $10/MWh, and 60 MW of energy at an energy price of $110/MWh. This TMSR clearing price of $10/MWh makes the generator indifferent between providing additional energy and providing TMSR. If it provides additional energy at this $110/MWh LMP, it will earn $110/MWh in revenue but will also incur its offered cost of $100/MWh to produce that energy, for a net profit of $10/MWh. The $10/MWh TMSR price is equal to this $10/MWh opportunity cost the resource incurs by providing reserves rather than energy, and ensures that the resource is no worse off as a result of following the ISO's dispatch signal to produce 60 MW of energy (rather than 100 MW).

If re-dispatch is required to maintain sufficient thirty-minute capability within a reserve zone, there is potential for higher reserve prices within that zone than across the system more broadly. Such price separation, however, is an exceedingly rare occurrence in recent years.

6.4.1 Reserve Constraint Penalty Factors (RCPFs)

Reserve Constraint Penalty Factors (RCPFs) are pre-determined $/MWh values that reflect the maximum cost the market is willing to incur in order to satisfy reserve requirements. When the cost to satisfy a reserve requirement exceeds the RCPF, they system procures fewer reserves than required and becomes deficient of reserves.

Each reserve constraint has a corresponding RCPF, as shown in Table 6-1 below.

Table 6-1: Reserve Constraint Penalty Factors

Requirement	RCPF ($/MWh)
Ten-Minute Spinning Reserve Requirement (10-min spinning)	50
System Ten-Minute Reserve Requirement (10-min non-spinning)	1,500
System Minimum Total Reserve Requirement (30-min)	1,000
System Total Reserve Requirement (30-min)	250
Zonal Reserve Requirement (30-min)	250

When the system becomes reserve deficient, and an RCPF is 'activated', then that RCPF plays a role in the calculation of reserve product clearing prices and energy prices, as discussed next. Further, certain RCPF activations trigger capacity scarcity conditions under the Forward Capacity Market's Pay-for-Performance rules (see Section 9).[40]

6.4.2 Participation Payment Principle

Reserve prices reflect the *participation payment principle.* This principle states that a product must be compensated in a manner that reflects the value it provides to the system by satisfying one or more constraints to ensure compensation that is commensurate with the value that product provides to the system. As noted above, certain reserve products can contribute to (or, *participate* in) satisfying more than one reserve constraint. Each product is paid a reserve price that reflects the value to the system of each reserve constraint it contributes to satisfying.[41]

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[40] The relationship between RCPF pricing and capacity scarcity conditions is defined in Section III.13.7.2.1 of the ISO New England Tariff. https://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1.

[41] In technical terms, this value is defined as the constraint's 'shadow price.' It represents the cost that would be incurred at the margin if another resource, with greater opportunity cost, were required to satisfy the reserve requirement.

For example, suppose re-dispatch of the system is required in order to satisfy the system total 30-minute reserve requirement, and the resulting opportunity cost incurred by the resource that is dispatched down to provide that reserve is $40/MWh. All of the reserve products (TMSR, TMNSR, and TMOR) are able to contribute to satisfying the 30-minute reserve requirement, and therefore, all reserve products are paid this $40/MWh price (TMSR price = TMNSR price = TMOR price = $40/MWh).

Now, suppose instead that re-dispatch of the system is required in order to satisfy the system total 10-minute reserve requirement, and resulting opportunity cost incurred by the resource that is dispatched down to provide that reserve is $70/MWh. Only two reserve products contribute to satisfying the total 10-minute reserve requirement: TMSR and TMNSR. These two products, therefore, are paid a reserve price of $70/MWh (TMSR price = TMNSR price = $70/MWh). The TMOR product does not contribute to the constraint causing re-dispatch, and therefore is not paid this price.

The RCPFs discussed in the previous section can also play a role in setting reserve and energy prices. For example, suppose that there is insufficient reserve capability available to satisfy the total 10-minute reserve requirement. As a result, the system is deficient of 10-minute reserves (combined TMSR and TMNSR) the RCPF associated with the total 10-minute reserve requirement RCPF is 'activated.' The price paid to the two products that participate in this constraint will reflect this RCPF. The TMNSR price will be equal to $1,500/MWh, and the TMSR price will be equal to at least $1,500/MWh.[42] The real-time LMP will generally also reflect activated RCPFs as an 'adder' to the energy price, providing a strong price signal to provide supply capability to the market.[43]

If the system is short of all reserve products, the TMSR price will reflect the sum of all relevant RCPFs, and as such the highest possible reserve clearing price is $2,550/MWh ($50 + $1,500 + $1,000). This value will generally serve as an 'adder' to the real-time energy price.

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[42] Recall that TMSR also participates in satisfying the TMSR requirement. So, if the TMSR requirement is also binding or violated, then the TMSR price could be higher than the TMNSR price.

[43] The only exception to this statement occurs if the system is ramp-limited, rather than capacity-limited, for reserves.

Section 7
Regulation Market

7.1 Introduction

The regulation market procures an essential reliability service that balances supply and demand over very short time intervals, which also assists in maintaining the frequency of the entire Eastern Interconnection. For example, the energy market requires regulation services when forecast load and actual load diverge, when generators do not meet the ISO's dispatch instructions, or when import or export power flows deviate from expectations.[44]

> The **regulation market** is a *spot* market that compensates generators that balance supply levels in response to second-to-second variations in electric power demand.

7.2 Market Clearing

The regulation market consists of several key elements:

- the amount of regulation capability needed for a particular time interval (i.e., the regulation requirement),
- the supply offers of regulation-capable resources to provide regulation service and capacity,[45]
- market clearing based on the least-cost combination of resources to satisfy the regulation requirements; the highest-priced resource(s) chosen to provide regulation sets the regulation clearing prices for service and capacity, and
- the regulation clearing prices which are used to determine the compensation (i.e., payments or "settlement") provided to resources providing regulation.

To administer the market, the ISO develops hourly regulation requirements for the real-time energy market (i.e., quantities of regulation "capacity" and "service" needed to ensure the reliable operation of the grid). Regulation resources provide supply offers indicating their availability and the cost (offer prices) for providing regulation. Regulation resources provide offers for "service" (the up and down movement of the resource while providing regulation) and "capacity" (a measurement of the MW range within which the resource is being moved up and down while providing regulation).[46]

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[44] The objective of the regulation market is to acquire adequate resources such that the ISO meets NERC's Real Power Balancing Control Performance Standard (BAL-001-2). This NERC standard can be accessed at http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf.

[45] The most common types of resources providing regulation services are generators and batteries.

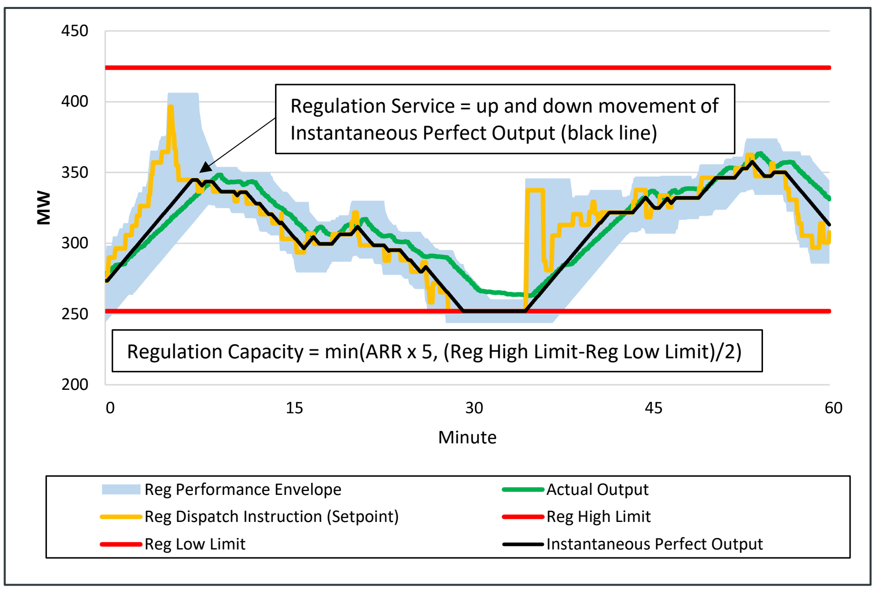
[46] Note that ISO adjusts participants' regulation capacity price offers. The adjustments reflect estimates of energy market opportunity costs and incremental cost savings. Opportunity costs represent the expected value to the regulation resource of foregone energy market opportunities, when providing regulation. Incremental cost savings represent the reduction in total system cost provided by a specific regulation offer, when compared to the next most expensive offer.

The ISO utilizes an optimization model to determine the least-cost combination of regulation resources (based on their offers) to meet the regulation requirement. When the market optimization has chosen the least-cost cohort of regulation resources, the regulation prices for "service" and for "capacity" are determined by the highest offer prices of the resources selected to provide regulation.[47] Regulation prices are determined for each five-minute pricing interval in the real-time energy market.

7.3 Capacity and Service

Figure 7-1 depicts a traditional generator's operation while providing regulation.[48] To balance supply and demand over very short time intervals, generators providing regulation increase and decrease their output ("actual output", green line) within a predefined range. This range is defined by the regulation low limit and the regulation high limit (red lines).[49] The generator responds to setpoint instructions (similar to dispatch instructions) from the ISO (yellow line). The generator receives setpoint instructions every four seconds. The generator is expected to adjust its output consistent with the setpoint instructions by ramping to follow the setpoint at a rate no slower than its offered automatic response rate; this is shown as the instantaneous perfect output (IPO) in the figure (black line).[50]

Figure 7-1: Regulation Capacity and Service by Hypothetical Generator



[47] The ISO can override the optimization model's least-cost selections. When the ISO overrides the optimization model's selections, the most expensive resources selected to provide regulation capacity and service (including the manual selections) will set the prices for that pricing interval.

[48] For detailed information on the regulation market and performance monitoring, see: https://www.iso-ne.com/static-assets/documents/2015/02/2015_regulation_market_ppt_slides.pdf or the same material with additional narration through ISO-TEN at: https://www.iso-ne.com/static-assets/documents/2015/01/reg_mkt_01_19_2015.htm

[49] This range must fall within the generator's offered economic minimum and maximum limits.

[50] The automatic response rate (ARR) is the rate (in MW/minute) at which the generator can change its output while providing regulation. The ARR is contained in the generator's offer to provide regulation.

The ISO adjusts the generator's regulation compensation to reflect performance while providing regulation. For a generator to receive full compensation for providing regulation, it must control the generator's output (green line), such that the output is within the highlighted performance envelope (blue-shaded region). In this example, the generator's performance score will be negatively affected by failing to maintain output within the performance envelope at approximately minute 30 (i.e., green line above shaded region).

The regulation service compensation represents the absolute value of the movement in the IPO multiplied by the regulation service prices, and is adjusted by a generator's performance score (i.e., its ability to provide regulation within the performance envelope).[51] The capacity compensation similarly is the amount of capacity provided by the generator multiplied by the capacity prices, and is adjusted by a generator's performance score. Regulation capacity is defined as the minimum of (1) five times the automatic response rate (i.e., the rate (MW/Minute) at which the generator can change its output), and (2) one-half of the difference between the regulation high and low limits.

7.4 Settlement

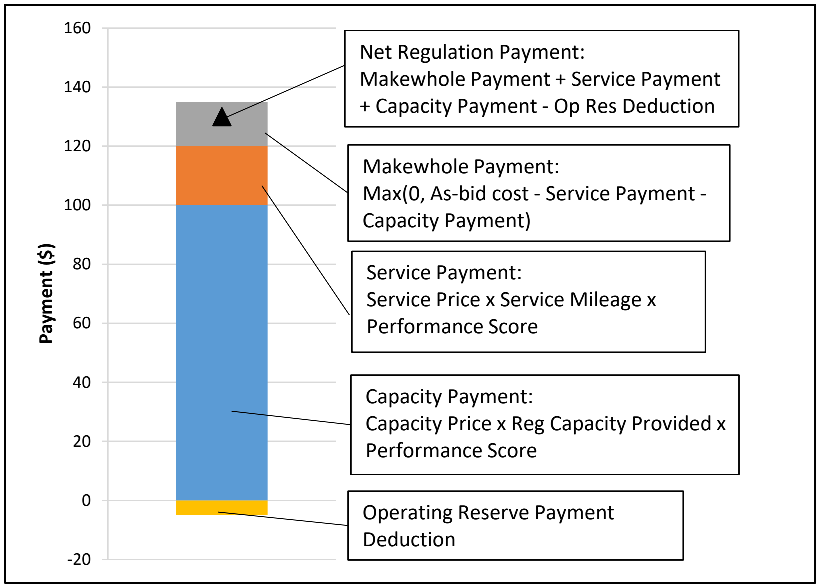
Regulation payments consist of several components: a capacity payment, a service payment, a make-whole payment, and an operating reserve charge. Figure 7-2 indicates the payments that regulation resources are entitled to collect when providing regulation.

Capacity and service payments simply represent the product of the quantities of regulation capacity and service provided by a regulation resource, the clearing prices for capacity and service, and a performance score. The performance score adjusts payments to account for poor performance when providing regulation.[52]

[51] Service compensation is based on the IPO to avoid providing an incentive for regulation resources to exaggerate up and down movement when providing regulation.

[52] The performance score ranges from 0 to 1. Performance scores below 1 result in a reduction of regulation payments to resources. The regulation capacity payment, for example, equals: regulation capacity MW x regulation capacity clearing price x performance score.

Figure 7-2: Regulation Settlement



Capacity and service payments typically comprise a significant proportion of overall regulation payments. The make-whole payment (essentially uplift) ensures that a regulation resource fully recovers the as-bid costs of providing regulation capacity and service, including the energy market opportunity cost component of that compensation. The operating reserve charge deducts a portion of operating reserve revenue from regulation payments. This deduction occurs when the regulating range overlaps with operating reserve designations. Providing operating reserves within the regulating range is not feasible, leading to the deduction of any compensation for those reserve designations.

Section 8
Voltage Support and Blackstart Services

8.1 Introduction

Voltage support and blackstart service represent two additional types of ancillary services that are required for the reliable delivery of energy. Prices for these products are set administratively by the ISO rather than determined through a market or auction mechanism.

Voltage support ensures the reliable flow of power on the grid, by maintaining voltage levels within an acceptable range. Blackstart service allows for the restoration of power flows on the grid, when there has been a partial or complete shutdown of the transmission system (i.e., a blackout).

8.2 Voltage Support Service

The ISO controls voltage levels on the transmission system through reactive power dispatch.[53] The ISO dispatches resources (generator and non-generator) to produce or absorb reactive power. The eligibility criteria for providing voltage support include:

- the resource is dispatchable (or operationally-controlled) by the ISO,
- the resource provides measurable dynamic reactive power voltage support, and
- the resource's automatic voltage regulating equipment status is telemetered to the ISO.[54]

Depending on resource type (generator or non-generator), payments to resources providing voltage support may include certain types of energy market opportunity costs and payment rates contained in the ISO's Tariff.[55] Generators providing voltage support receive two types of payments: fixed and variable. The fixed payment (i.e., capacity cost) provides compensation for maintaining the generator's ability to provide voltage support. The variable payments (lost opportunity cost, cost of energy consumed, cost of energy provided) provide cost recovery to the generator for following the ISO instructions for out-of-merit energy dispatch.

8.3 Blackstart Service

Blackstart service utilizes generators to restore power flows on the transmission grid after a blackout. Blackstart generators have the ability to start up without the need for external power supply from the transmission grid. The owners of blackstart-capable resources can request to provide blackstart service to the ISO. The ISO reviews these requests, considering a resource's

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[53] The ISO defines reactive power in its Glossary (https://www.iso-ne.com/participate/support/glossary-acronyms/#r). The electrical engineering portal indicates that …"reactive power (VARS) is required to maintain the voltage to deliver active power (watts) through transmission lines." (electrical-engineering-portal.com)

[54] For a full listing of eligibility criteria, see the Open Access Transmission Tariff, Schedule 2, Section II.A. See: https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf

[55] Ibid., Section IV.

location and blackstart capabilities.[56] It selects blackstart resources based on their ability to support the ISO's transmission system restoration plan. Once selected, the ISO enters into an agreement with the resource owner to provide blackstart service. Transmission customers cover blackstart costs, since the ISO obtains the service on behalf of transmission owners. The payments to resources providing blackstart service are set according to payment rates contained in the ISO's Tariff.[57] Blackstart resources receive payments for both the capital and operations and maintenance (O&M) costs of maintaining the blackstart capability.

[56] See the Open Access Transmission Tariff, Schedule 16, Section 1, for the eligibility requirements.

[57] Ibid., Section 5 and Appendix A to Schedule 16.

Forward Capacity Market

Section 9: Forward Capacity Market

Section 9
Forward Capacity Market

9.1 Introduction

New England's electricity market requires adequate capacity supply to meet expected energy demand and ancillary service requirements. Suppliers that provide this capacity in a competitive market require sufficient revenue streams from the wholesale markets to recover costs of providing their services. The forward capacity market (FCM) provides an additional revenue stream for the purpose of allowing revenue adequacy across the markets. FCM payments are paid to suppliers that are selected to supply capacity three years in advance of delivery, and the ISO procures sufficient capacity to satisfy the '1-in-10' loss of load planning objective on average.[58]

Any asset or import that supplies energy to New England's energy market can become a "capacity resource" and collect this additional stream of revenue. In exchange for this payment, capacity resources assume a Capacity Supply Obligation (CSO), which creates a set of obligations for the resource.

The **forward capacity market** ("FCM") is a *forward* market that allows participating entities, or resources, to sell their capacity in advance of the actual delivery period.

The functions of the FCM can be distilled to three main objectives:

- **To provide "missing money" to energy suppliers** – in the energy market, suppliers are incented to sell their output at their marginal cost. However, marginal-cost bidding of energy ignores the fixed costs associated with building and running a power plant or demand reduction asset. By obtaining a CSO, suppliers have an opportunity to recover their fixed costs, or "missing money," through the capacity payments provided by the FCM.

- **To procure a sufficient and cost-effective resource mix in New England** – the FCM auction process spans three years and offers numerous opportunities for capacity procurement at the lowest possible cost. At the end of the three-year period, the ISO should have enough obligated capacity to operate the grid at the ISO-defined 1 day-in-10 years loss of load expectation.[59] Auction prices are intended to send entry and exit signals for capacity and will be a function of suppler offer prices and the willingness of demand to pay for capacity at various levels of reliability.

- **To incent reliability through resource obligation** – all resources receiving capacity payments through the FCM fulfill their obligation by offering their capacity into the energy market. The requirement of energy market bidding is called the "must-offer requirement" and helps ensure the ISO has access to all available capacity. Capacity resources also have a financial obligation to contribute their share to meeting load and

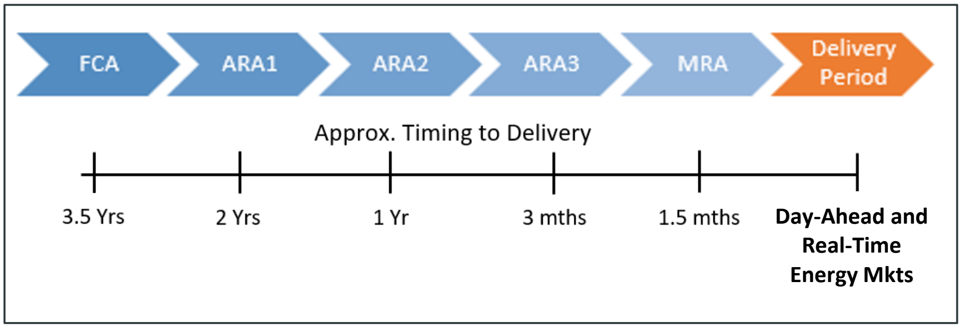
[58] This planning criteria means that, in expectation, the system will shed load no more frequently than one day in ten years.

[59] More information on the capacity requirements for ISO New England can be found in Section 12 of Market Rule 1.

reserve requirements during capacity scarcity conditions. This financial obligation is termed "Pay-for-Performance".

The upcoming sections are organized around the three-year FCM auction process timeline, from initial procurement in the primary auction to delivery of capacity in the energy markets. A simplified version of the FCM timeline is shown in Figure 9-1.

Figure 9-1: Simplified FCM Timeline



The first opportunity that a capacity resource has to sell its capacity for a given delivery period is the annual Forward Capacity Auction (FCA), which is discussed in more detail in Section 9.2. After the FCA, capacity resources can modify their positions in one of the three annual reconfiguration auctions (ARA1, ARA2 and ARA3), discussed in more detail in Section 9.3. The last opportunity that a capacity resource has to alter its CSO before the delivery period is during a monthly reconfiguration auction (MRA), discussed in more detail in Section 9.4. The final section, Section 9.5, concludes by detailing the requirements associated with holding a CSO during the delivery period.

9.2 Forward Capacity Auction

The Forward Capacity Auction (FCA) is the primary auction mechanism for resources to sell their capacity and take on a CSO position at a forward price. Around February of each year, the ISO holds the FCA for the delivery period three years out. For example, the primary auction held in 2023 (FCA 17) will obligate capacity for the power year from June 2026 – May 2027.[60] Energy suppliers participating in the FCA must go through a qualification process before entering the auction. Any qualified resource that clears in the FCA will receive a year-long CSO for the future delivery period.

9.2.1 Qualification

Prior to the start of the auction, the ISO qualifies resources depending on the maximum amount of capacity they can provide to New England's grid. The ISO-determined maximum capacity, more commonly called qualified capacity (QC), represents the upper limit of capacity a resource can offer into the FCA. In general, resources are qualified in the following manner:

- **Intermittent resources (solar, wind, hydro, etc.)** – QC is represented by the median output (in MW) during peak reliability hours in both the summer and winter seasons.

[60] A capacity year differs from a traditional calendar year. A capacity year starts in June and runs to the following May.

- **Non-intermittent resources** – QC closely resembles the resource's installed capacity based on tested capability, with seasonal adjustments for ambient temperature effects.

9.2.2 Bids and Offers of Capacity

A qualified capacity resource can participate in the auction through a variety of bids or offers. The bids or offers available to a capacity resource, shown in Table 9-1 below, depend on its classification: "new" (it is the resource's first FCA) or "existing" (the resource has received CSO in a prior FCA).[61]

Table 9-1: FCA Bid and Offer Descriptions

Resource Type	Bid/Offer Type	Bid/Offer Subtype	Description
New	**New Supply Offers**	-	Offer of new MW to the capacity and energy market, once cleared the resource becomes "existing" in subsequent FCAs
Existing	**Delist Bids**	Retirement	Bid to permanently remove MW from the capacity and energy market
		Permanent	Bid to permanently remove MW from the capacity market
		Static	Bid to remove MW from the capacity market for one year
		Dynamic	Bid to remove MW from the capacity market for one year (priced below mitigation threshold, DDBT – see next section)

9.2.3 FCA Price and Capacity Parameters

The delist bids and new supply offers submitted by capacity resources represent the lowest price at which they are willing to sell their capacity and assume a CSO. The ISO selects capacity resources with the lowest possible offered price in order to meet a given level of reliability. To align the financial needs of resources with the system capacity needs of the New England grid, the ISO establishes a set of FCA parameters to ensure the auction clears the most economically efficient allotment of resource offers.

Some of the key FCA parameters are described in Table 9-2.

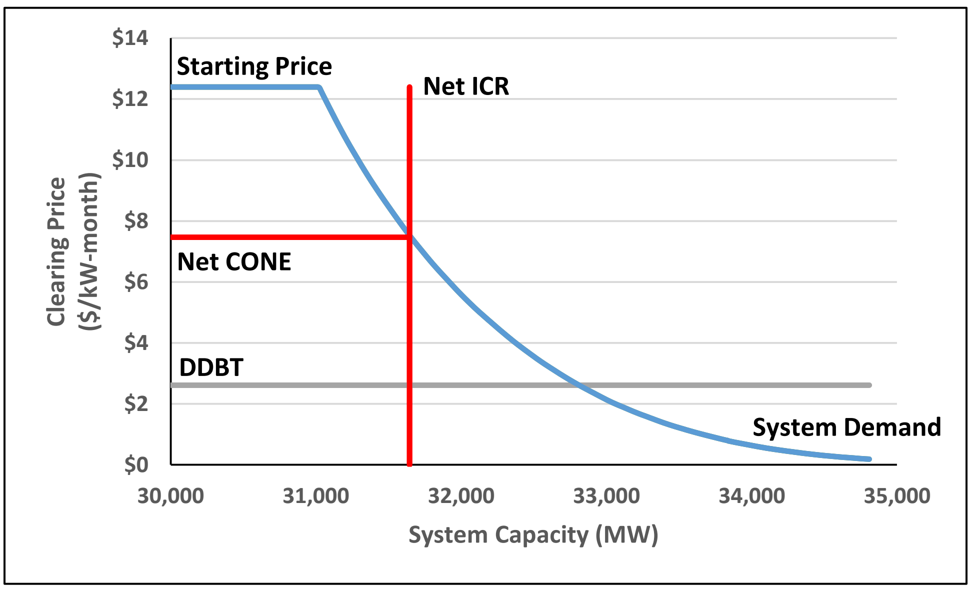
[61] Import resources are a special case in the FCA. Despite most import resources entering consecutive FCAs, all import resources are qualified as new resources and submit new supply offers.

Table 9-2: Key FCA Parameters

Price Parameter	Description
Net Cost of New Entry (Net CONE)	Estimated capacity price ($/kW-month) for the reference unit[62]
FCA Starting Price	Scaled up Net CONE price (typically 1.6 x Net CONE) to begin auction
Dynamic Delist Bid Threshold (DDBT)	Price at which delist bids no longer need to be reviewed by the IMM and can actively participate in the auction
Capacity Parameter	**Description**
Net Installed Capacity Requirement (Net ICR)	The minimum amount of capacity (MW) needed to meet system-wide reliability criteria

The above parameters (with the exception of the DDBT) are used to adjust the administrative demand curve for each FCA by reflecting changes in the ISO load forecasts or changes to the estimated costs of building new generation. The demand curve reflects the costs consumers are willing to pay for capacity at various levels of reliability. An example system-level demand curve is shown in Figure 9-2 below.

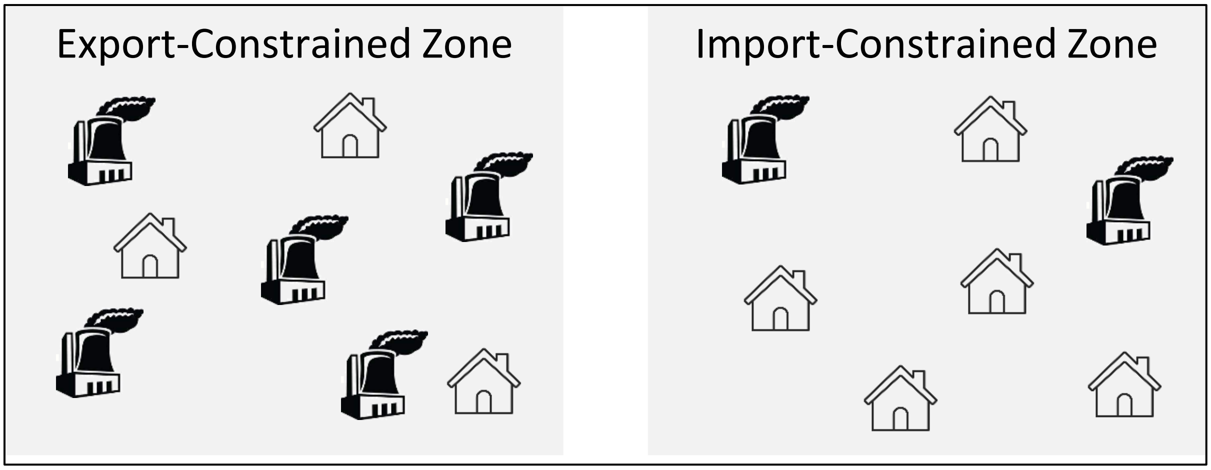
Figure 9-2: Example FCA Demand Curve with Parameters



While the ISO must procure enough capacity in the FCA to serve the entire New England grid, the transmission system limits the ability of certain areas in New England to import or export power to/from the rest of the system. To account for these limitations, the ISO models capacity zones in the auction. Resources are mapped to a capacity zone depending on their location and can receive a different capacity payment depending on the value of their supply relative to their location. A simplified demonstration of modelled capacity zones is shown in Figure 9-3 below.

[62] The reference unit is modeled to reflect the annual levelized capital and fixed costs a new entrant would incur to enter the ISO-NE capacity market over its estimated project life.

Figure 9-3: Demonstration of Constrained Capacity Zones



Export-Constrained Capacity Zones – Areas of New England with greater capacity supply than customer demand, and limited transmission capability to move excess supply out of the area, are classified as export-constrained. Export-constrained capacity zones will have a maximum amount of CSOs that they can clear during the primary auction, called the *Maximum Capacity Limit*. Auction clearing prices can be lower in export-constrained capacity zones to reflect the diminished marginal value of surplus supply. For example, a 100 MW resource in an export-constrained zone may receive a lower price than an equivalent resource in an unconstrained zone, reflecting its lower reliability value.

Import-Constrained Capacity Zones – Areas of New England with greater customer demand than capacity supply, and limited transmission capability into the area are classified as import-constrained. Import-constrained capacity zones will have a minimum amount of CSOs that they must clear in the primary auction, called the *Local Sourcing Requirement*. Auction clearing prices can be higher in import-constrained capacity zones to reflect the premium reliability value of additional supply in the area.

9.2.4 Clearing the Forward Capacity Auction

Once participating resources prepare their bids/offers and the ISO establishes the auction parameters, the FCA is run with a descending-clock auction format. Beginning at the auction starting price, resource offers and bids are removed over multiple rounds from highest to lowest price until the remaining supply of resources equals the remaining demand for capacity.

The remaining bids are entered into a market clearing engine which determines the capacity purchased from each supplier and the final capacity rate in dollars per kW per month ($/kW-month). All resources that clear in the FCA will be paid the auction-clearing rate regardless of the price at which their bids and offers were submitted. As mentioned above, import- and export-constrained zones may have different auction clearing prices than the rest of the system.

In some cases, a substitution auction can occur immediately after the FCA to allow for the transfer of CSOs between sponsored policy resources and existing retiring resources.[63]

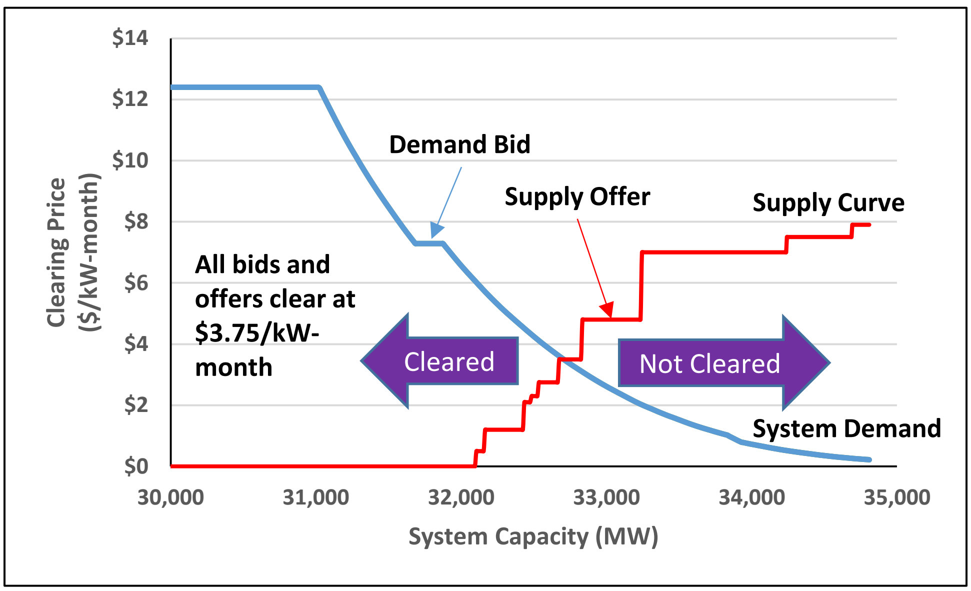
9.3 Annual Reconfiguration Auctions

After the completion of the FCA, capacity resources have numerous opportunities to adjust their CSO position. For example, a resource owner may wish to adjust its position to account for expected availability of capacity for the delivery period or expected performance during capacity scarcity conditions.

The ISO holds three annual reconfiguration auctions (ARAs) in the three years between the FCA and delivery period. The ARAs are sealed-bid auctions where capacity resources submit bids and offers before the auction. Capacity resources that participate in the ARAs can submit supply offers (increase CSO position) or demand bids (decrease CSO position) depending on their desired adjustment.

A simplified example of an ARA auction clearing is shown in Figure 9-4. The ISO constructs a demand curve that represents an updated forecast of system-wide capacity needs combined with resource demand bids. The supply curve is comprised of resource supply offers and begins at the MW amount (approx. 32,000 MW below) of capacity resources not participating in the ARA. The intersection of the supply and demand curves determines the auction-clearing price paid to all cleared resources.

Figure 9-4: Example of ARA Supply and Demand Curves



Participants also have the ability to hedge or lock-in a capacity price through a bilateral

Annual Reconfiguration Transactions (ARTs) facilitate the shedding and acquiring of CSOs between two resources at a fixed price in an annual reconfiguration auction. In order to execute an ART, the acquiring resource (being paid to pick up CSO) and the shedding (paying to get rid of CSO) must agree on a price and amount of CSO to transact. Once the ARA is complete, the ART will settle such that the difference between the auction clearing price and the ART price is transferred between the two resources so that both effectively settle at the price agreed upon in the ART.

arrangement known as an Annual Reconfiguration Transaction.

9.4 Monthly Reconfiguration Auctions

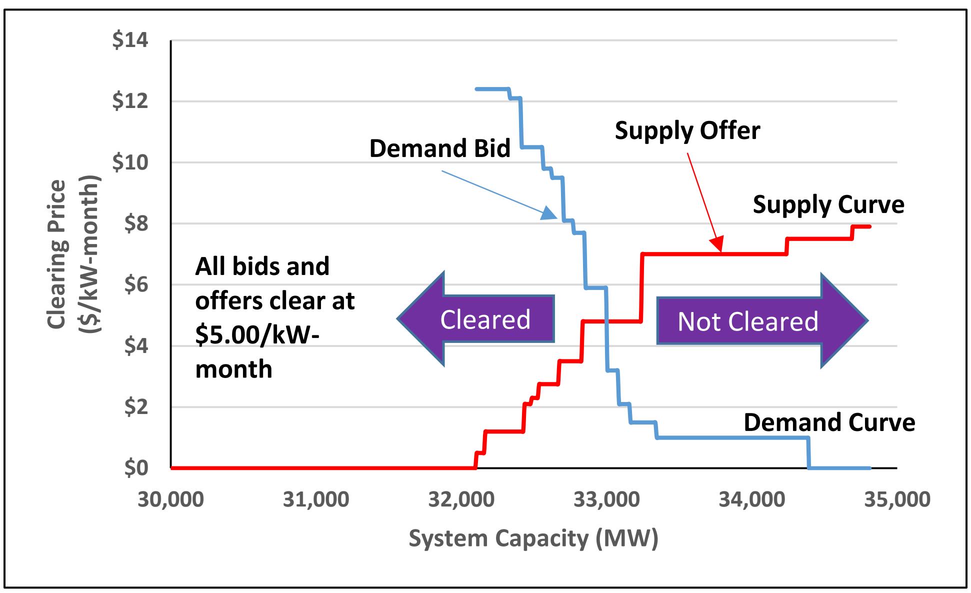
The shortest term for a CSO is monthly, which is consistent with the monthly settlement construct for capacity. As with annual adjustments, a participant may wish to adjust its monthly obligation for a number reasons, including to account for availability expectations due to ambient temperatures, maintenance, or as a risk management strategy. Some examples of monthly CSO adjustments include:

- solar resources only obtain CSOs in the summer months due to decreased winter capability,
- thermal resources receive greater qualified capacity values in the winter months due to colder ambient temperatures, and
- resources undergoing a significant planned outage may want to shed their CSOs in the months they will be unavailable.

To facilitate month-to-month capacity adjustments, the ISO administers monthly reconfiguration auctions (MRAs) about two months prior to each delivery month.

Similar to ARAs, MRAs allow capacity resources to submit demand bids to shed CSO or supply offers to obtain CSO. However, unlike ARAs, the monthly auctions do not use a system-wide demand curve. Instead, all demand bids and supply offers are cleared against each other to generate a market-clearing price. A simplified example of an MRA auction clearing is shown in Figure 9-5 below.

Figure 9-5: Example of MRA Supply and Demand Curves



Monthly bilateral contracts provide another opportunity for resources to adjust their monthly CSO MWs in addition to the monthly reconfiguration auctions. Rather than exposing their CSO MW to MRA clearing prices, two resources can engage in a bilateral trade, set at an agreed-upon price and MW amount. Unlike ARTs in the Annual Reconfiguration Auctions, monthly bilateral contracts actually exchange CSO between the two resources.

9.5 Capacity Delivery Period Requirements

Throughout the delivery period, a resource's CSO measures against their physical energy supply through design features incenting or requiring delivery, such as the must-offer requirement, failure-to-cover charges, and the Pay-for-Performance (PfP) program. Each of these is discussed in more detail below.

9.5.1 Must-Offer Requirement

The must-offer rule creates the physical obligation that capacity resources must be available for energy dispatch by the ISO. It requires a capacity resource to submit energy offers into the day-ahead and real-time energy markets at a quantity greater than or equal to their CSO to the extent that it is physically available. In other words, the capacity of a resource on outage or not expected to be available due to weather (e.g., wind) is not required to be offered under the must-offer rule. For example, a 100 MW resource with a 100 MW CSO must offer their full 100 MW of supply into the day-ahead market. The same 100 MW resource with an 80 MW CSO is only required to offer 80 MW of supply into the day-ahead market under this rule.

9.5.2 Failure-to-Cover Charges

This settlement mechanism incents resources to cover their CSO position, particularly resources facing a delay to the start of their commercial operation. The failure-to-cover charge is applied to capacity resources whose maximum demonstrated output (MDO) is less than their CSO. A resource's MDO is the highest MW output measured in the prior six years. For new resources without any historical MW output, their MDO is replaced with a demonstration of sufficient installed capacity just prior to energy delivery. Any resource with unproven capacity (CSO > MDO) will be charged for failing to cover their obligation.

9.5.3 Pay-for-Performance (PfP)

The PfP rules measure resource performance during a capacity scarcity condition (CSC), which occurs when the system is short of total ten-minute or total thirty-minute reserves and the associated reserve constraint penalty factors are triggered (see Section 6.4.1). Together with very high energy and reserve prices during such events, the PfP settlement rules provide strong incentives for supply resources to perform by making their capacity available to the market.

The PfP rules and the associated performance rate make up the spot delivery component of the two-settlement construct employed in the FCM. Capacity resources have a financial obligation to perform consistent with their forward position (their CSO) and their expected contribution to meeting the system's load and reserve requirements. Deviations (over- or under-delivery relative to their contracted position) are paid or charged at the performance payment rate. Non-capacity resources do not have any financial obligation, so deviations can only be positive, thereby resulting in a payment for any contribution to meeting the systems load and reserve requirements.

For each capacity scarcity condition, the ISO will measure how well each resource performed compared to their CSO. The ISO calculates a "performance score" which is used to determine credits or charges for over- or under-performance. This calculation of credits and charges is shown in Figure 9-6 below.

Figure 9-6: PfP Performance Credit/Charge Equation

$$\textit{Performance Credit/Charge} = (\textit{ACP MW} - \textit{CSO MW} * \textit{BR}) * \textit{PPR}$$

A capacity resource's performance credit or charge can be simplified as the relationship between the resource's performance and the system's performance. Descriptions for the terms in the PfP performance score equation can be found in Table 9-3 below.

Table 9-3: Key Parameters in Determining PfP Credits or Charges

Parameter	Description
Actual Capacity Provided (ACP)	Amount of MWs (energy and reserves) a resource provides during an interval of capacity scarcity.
Balancing Ratio (BR)	System-wide load and reserve requirements divided by system-wide CSO.
Performance Payment Rate (PPR)	In $/MWh, the rate at which over-performers are credited and under-performers are charged during a scarcity event.

The following example demonstrates how PfP performance scores are calculated after a scarcity event.

Assume a total system CSO of 20,000 MW, and load and reserve requirements of 15,000 MW. The balancing ratio equals 75%, meaning that each capacity resource is financially obligated to contribute 75% of its contracted capacity (CSO) to meeting load and reserve requirements.

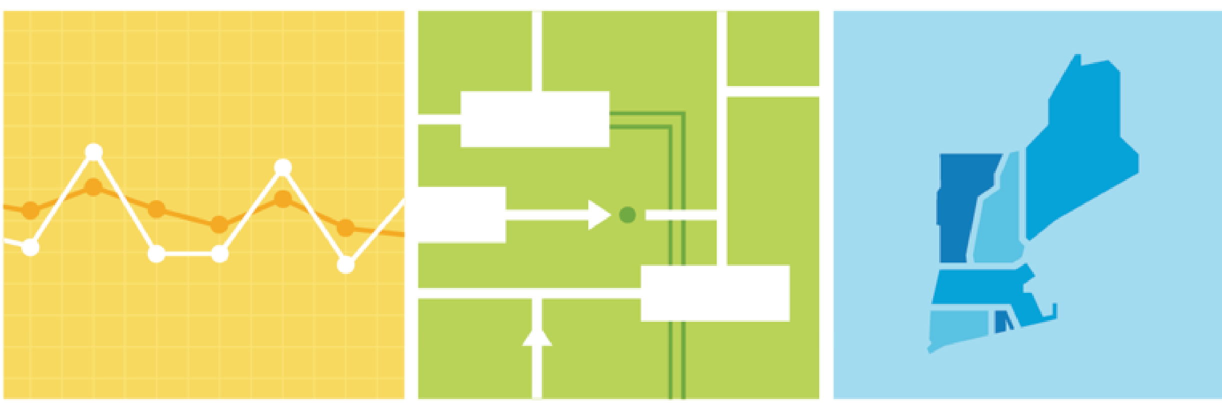
Resource A has CSO of 100 MW. During a capacity scarcity condition, Resource A has an ACP of 80 MW, because it provides 75 MW of energy and 5 MW of reserves. This resource's share of load and reserve requirements is during the capacity scarcity condition is its 100 MW CSO multiplied by the balancing ratio of 75%, or 75 MW. The resource's performance score is the amount by which the ACP exceeds this share, and is 5 MW (80 – 75). Resource A will receive a payment for 5 MW of over-performance at the performance payment rate (in addition to its base/forward CSO payment).

Conversely, suppose Resource B also has a 100 MW CSO, but has an ACP of only 70 MW during the capacity scarcity condition. This resource has under-performed relative to its obligation during the CSC, and will receive a charge for its 5 MW of under-performance at the performance payment rate. Further, suppose Resource C is a non-capacity resource (i.e., it has a CSO = 0 MW) and provides 70 MW of energy during the CSC. This resource has an ACP = 70 MW, and will receive payment for the full 70 MW at the performance payment rate. Resource A and B retain their base capacity revenues from the auction in which they cleared, however Resource B sees a reduction in its total capacity revenue. Under the PfP construct, participants can lose more than their base revenue due to resource under-performance, but there are limits on losses through stop-loss provisions (which are not covered in this document).

Every year, the ISO estimates the number of capacity scarcity condition hours that will occur in future delivery periods. The ISO expects more scarcity conditions with lower levels of capacity supply obligations and fewer scarcity conditions with higher levels of capacity supply obligations. The capacity scarcity hour estimate informs capacity resources as to how likely it is that PfP events will affect their underlying capacity payments.

Congestion and the Financial Transmission Rights Market

Section 10: Financial Transmission Rights Market



Section 10
Congestion & Financial Transmission Rights Market

10.1 Introduction

Transmission congestion – which happens when the power flowing across a transmission element (e.g., a transmission line) reaches the limit of what that element can reliably carry – can create locational differences in energy prices in New England's energy market construct. These locational price differences create risk for market participants (this risk is commonly referred to as "basis" risk), who often purchase or sell energy using contracts that settle at the price of a liquid trading hub but whose generation or load are compensated or charged based on the pricing at individual nodes.[64] For example, a load-serving entity (LSE) in a high-demand area (e.g., Boston) may be at risk of having to purchase energy at high prices if the transmission system into the area is insufficient to deliver the most economic generation from the system into the area. Conversely, a generator that is interconnected in part of the transmission system that has a limited export capability (e.g., Northern Maine) may be at risk of receiving a reduced price for its energy if the transmission system is incapable of delivering that energy to the rest of the system. Financial transmission rights (FTRs) exist for situations like these – to provide market participants with a financial instrument that can help them manage risk associated with transmission congestion.[65]

The **financial transmission rights ("FTR") market** is a market that allows participants to purchase financial instruments that can be used to hedge or speculate on transmission congestion in New England's day-ahead energy market.

10.2 Auctions

Market participants can obtain FTRs by participating in ISO-administered auctions for annual and monthly products. There are separate auctions for on-peak and off-peak hours.[66] The FTRs awarded in the two annual auctions have a term of one calendar year (i.e., January 1 to December 31), while the FTRs awarded in one of the monthly auctions have a term of one month.[67] FTRs can be purchased in all auctions, but can only be sold in the second annual auction or the monthly auctions as only FTRs that are owned (i.e., have been purchased) can be sold by participants (i.e., there is no short selling).

Table 10-1 below summarizes five important elements in a bid to purchase an FTR.

[64] In New England, the location often used to facilitate energy trades is called .H.INTERNAL_HUB and is usually referred to as the Hub.

[65] See ISO-NE Manual for Financial Transmission Rights (Manual M-06) and Section III.7 of ISO-NE Market Rule 1 for detailed information about FTRs. See: https://www.iso-ne.com/static-assets/documents/2018/10/manual_06_financial_transmission_rights_rev11_20181004.pdf

[66] On-peak hours are defined by the ISO as hours ending 8-23 on weekdays that are not NERC holidays. The remaining hours are off-peak hours.

[67] Information about the percent of the network made available in each FTR auction can be found in Section III.7.1.1 of Market Rule 1.

Table 10-1: Elements of an FTR Bid

Element	Description
Path	FTRs are defined between two points (i.e., pricing nodes): 1) the point of injection (or the "source") and 2) the point of withdrawal (or the "sink").
Price	The $/MW value the participant is willing to pay to acquire the FTR.
MW-amount	The size of the FTR (in MWs) the participant is willing to buy.
Term	The monthly or annual period to which the FTR applies (e.g., November 2021).
Period	The hours in which the FTR applies (i.e., on-peak or off-peak).

The objective of the FTR auction is to award FTRs in a way that maximizes FTR bid value while ensuring that the awarded set of FTRs respects the transmission system's limits under normal and post-contingent states. The process that limits the set of awarded FTRs based on the capability of the transmission system is called the simultaneous feasibility test. The ISO performs this test in order to increase the likelihood that the sufficient revenue is collected during the term of the FTR to be able to fully compensate FTR holders.

The Balance of Planning Period (BoPP) project, which was implemented in September 2019, gave market participants more opportunities to reconfigure their monthly FTR positions following the two annual auctions. Prior to the implementation of this project, market participants could only purchase or sell FTRs for a specific month in the auction that occurred during the month immediately prior to that effective month. For example, under the old design, if a market participant wanted to buy FTRs that would be effective for December 2021, it had to wait until the monthly auction that took place in November 2021. Under the BoPP design, ISO-NE now administers monthly FTR auctions for not just the next month (now called the *prompt-month* auction), but also for all the other months remaining in the calendar year (called the *out-month* auctions). This means that a participant that wants to buy December 2021 FTRs no longer has to wait until November 2021; it can purchase these FTRs in any of the out-month auctions that take place earlier in the year.

10.3 Settlement

This section provides an overview of the three components that make up the LMP, with special focus on the congestion component. This component forms the basis for an FTR's value (referred to as a target allocation) and the value of the congestion revenue fund (CRF), the ISO-NE fund used to pay FTR holders.[68] Both target allocations and the CRF are discussed in detail in this section.

10.3.1 The Congestion Component

As discussed in Section 2.2.3, the locational marginal price (LMP) at a node represents the marginal cost of serving an additional megawatt (MW) of load at that location at the lowest cost to the system. This price reflects not only the cost to produce the energy, but also the cost to deliver it to that specific location. Both line losses and transmission congestion can make it more expensive to deliver energy to certain parts of the transmission system.

[68] See Section III.5 of ISO-NE Market Rule 1 for more information about target allocations and transmission congestion revenue.

Accordingly, ISO-NE separates the LMP into three components: the energy component, the loss component, and the congestion component. The energy component is the same for all locations in the power system. The loss component reflects the dispatch of additional generation because some electric energy is lost during transmission. The congestion component reflects the additional system costs when transmission constraints prevent the use of the least-cost generation to meet the next increment of load. The decomposition of LMPs into these three components is done in order to determine how much of the difference in LMPs at two locations is due to losses versus transmission congestion. This separation allows market participants to hedge against transmission congestion (i.e., through the use of FTRs).

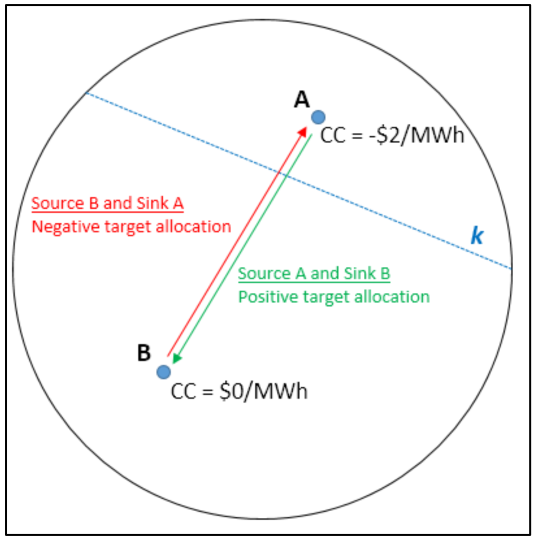
Transmission congestion is important because it imposes additional costs on the power system. The ISO models the operational limits of transmission elements as constraints in the economic optimization that it administers to determine the least-cost way of producing electricity. When the power flowing through a transmission element reaches its modeled limit in this optimization process, the constraint associated with that transmission element is said to "bind," and the transmission system experiences congestion. Much like a traffic jam on a highway, congestion in a transmission system represents a bottleneck: a location where the limited capability of some element has impeded the optimal flow in the system. In the case of transmission congestion, a transmission element has limited the extent to which the least-expensive generation can meet load in the system. Higher-cost generation must be dispatched to meet load, which raises the production cost of energy in the system.

10.3.2 Target Allocations

Target allocations represent the credits or charges associated with holding an FTR. For each hour that an FTR is effective, a target allocation is calculated by multiplying the MW amount of the FTR by the difference in the day-ahead congestion components of the FTR's sink and source locations. Positive target allocations occur when the congestion component of the sink location is greater than the congestion component of the source location in the day-ahead energy market. Positive target allocations represent revenue for FTR holders. Negative target allocations, which occur when the congestion component of the sink location is less than the congestion component of the source location in the day-ahead energy market, represent a charge to FTR holders.

To provide an example of how positive and negative target allocations can arise, Figure 10-1 is included below. This example is representative of congestion occurring in one hour in the day-ahead energy market. The black circle in this figure is the electrical network and the dashed blue line is binding constraint *k,* which limits the flow of power from the north of this electrical system to the south of the system. This figure also depicts two pricing locations: A and B. Location A is assumed to have a congestion component of -$2/MWh and location B is assumed to have a congestion component of $0/MWh.

Figure 10-1: Example of an Area with Negative Congestion Pricing in the Day-Ahead Market



In this example, FTR holders who hold paths sourcing from A and sinking at B would receive *positive* target allocations of $2/MWh because the congestion component at B ($0/MWh) is *greater* than the congestion component at A (-$2/MWh). Conversely, FTR holders who hold paths sourcing from B and sinking at A would incur *negative* target allocations because the congestion component at A (-$2/MWh) is *less* than the congestion component at B ($0/MWh).

10.3.3 Congestion Revenue and FTR Funding

The ISO settles the day-ahead and real-time energy markets by calculating charges and credits for all market activity that occurs at each pricing location (node) in the system. Energy market settlement is performed on each of the three components of the LMP separately. By design, the settlement based around the congestion component does not balance. The congestion charges are expected to exceed the congestion credits, and the surplus revenue is called congestion revenue. The ISO collects congestion revenue in both the day-ahead and real-time energy markets and this revenue forms the basis of the CRF. Payments to FTR holders with positive target allocations come from day-ahead and real-time congestion revenue and from FTR holders with negative target allocations. ISO-NE allocates any remaining year-end fund surplus to the entities that paid congestion costs during the year in a proportion to the amount of congestion costs they paid.[69]

10.3.4 FTR Examples

To better understand how an FTR could be used to the benefit of a market participant, we can consider a simple example of an LSE located in an import-constrained area (i.e., an area prone to positive congestion). To manage price risk, the LSE could decide to enter into an annual contract to buy energy at the day-ahead Hub price. However, the LSE would still bear basis risk,

[69] See Section III.5.2.6 of Market Rule 1 for more information about the distribution of excess congestion revenue. In practice, ISO-NE Settlements determines which participants incurred more congestion charges than congestion credits for the year across the day-ahead and real-time energy markets (i.e., had net negative congestion charges) and allocates the excess congestion revenue at year end to these participants pro-rata based on the magnitude of the net negative congestion charges.

as it is not serving load at the Hub, but rather in an area prone to positive congestion. In order to manage this risk, the LSE could purchase an FTR from the Hub to the zone where it serves load in both on-peak and off-peak auctions. This would entitle the LSE to the difference in the congestion components at these locations over the course of the year. The positive target allocations that accrued to these FTRs would offset the day-ahead congestion charges that the LSE incurred while serving load in this import-constrained area. The cost required to hedge this congestion risk would be the price the LSE paid to purchase the FTRs. Essentially, the LSE has hedged, or fixed, its congestion cost with its forward FTR position.

Importantly, participants can also purchase FTRs as a completely speculative instrument. For example, a market participant that has no load or generation position may want to purchase an FTR solely because it expects a certain amount of positive target allocations to accrue along a specific path.[70] This transaction would be profitable if the participant is able to purchase the FTR at a cost that is less than the revenue realized from holding the FTR. Such activity is not without risk, as expected patterns of congestion may not actually appear in the day-ahead market. In such cases, FTRs can quickly change from being a financial benefit to a financial obligation that requires payment. This sort of trading is considered speculative because it is an attempt to profit by engaging in a risky financial transaction that is not tied to any physical position in the ISO-NE marketplace. ISO-NE permits speculative trading in FTR auctions because it provides liquidity and competition to the market.

10.4 Auction Revenue Rights

The ISO primarily distributes the revenue it generates from the sale of FTRs in the different auctions it administers to Auction Revenue Rights (ARRs) holders.[71] These holders include both: (1) market participants that paid for transmission upgrades that made the additional sale of FTRs possible and (2) congestion-paying LSEs. The former group is referred to as Incremental ARR (IARR) holders. The MW-value of ARRs they receive is based on the additional amount of FTRs in the FTR auction that their transmission upgrade made possible. The remaining ARRs are allocated to congestion-paying LSEs in a four-stage process.[72] The majority of auction revenue is allocated through this four-stage process.

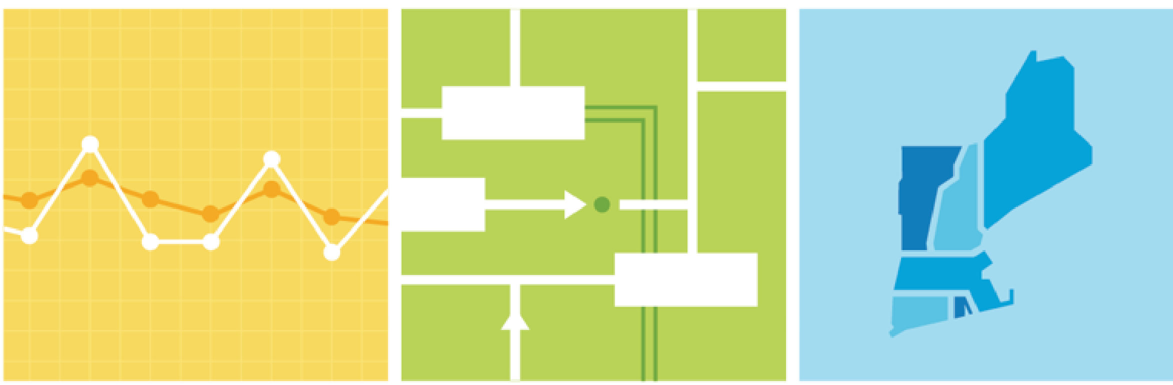
[70] This example is for a *prevailing flow* FTR, which is an FTR whose path is defined in the direction that congestion is expected to occur, based on FTR auction clearing prices. The holder of a prevailing flow FTR pays to acquire that FTR and then expects to receive positive target allocations as congestion occurs in the day-ahead energy market. Alternatively, a speculator could acquire a *counterflow* FTR. An FTR purchased at a negative price in an auction is called a counterflow FTR because its path is defined in the opposite direction that congestion is expected to occur based on the FTR auction clearing prices. The auction pays the counterflow FTR holder to take on this counterflow position, and this position will generally be profitable to the counterflow FTR holder if the total negative target allocations for this FTR are less than this payment from the auction.

[71] Some FTR auction revenue is also distributed to market participants that sell their previously-purchased FTRs.

[72] For more information about this allocation process, and about IARRs and ARRs in general, see Appendix C of Section III Market Rule 1. This appendix is dedicated specifically to this topic.

Market Power Mitigation

Section 11: Market Power Mitigation



Section 11
Market Power Mitigation

11.1 Introduction

In the context of the ISO's markets, market power refers to "any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products."[73] Market power mitigation refers to actions undertaken by the IMM to "minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions."[74] The IMM administers defined mitigation processes for addressing the potential exercise of market power in both the ISO's energy and capacity markets.[75]

11.2 Energy Market Mitigation

In the day-ahead and real-time energy markets, the IMM has implemented an ex-ante mitigation process to prevent the exercise of certain types of supplier-side market power. Energy market mitigation focuses on the economic withholding of generating capacity (supply) in the day-ahead and real-time energy markets.[76,77] Absent mitigation, the economic withholding of generating capacity – depending on the need for the capacity – may result in (1) energy market clearing prices (LMPs) that exceed expected competitive price levels or (2) elevated uplift (NCPC) payments to generators.

To limit economic withholding and its market impacts, the IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets.[78] Under certain conditions, the IMM will mitigate generator offers; that is, the IMM will replace the financial parameters of a generator's supply offer (i.e., start-up, no load, and segment energy offer prices) with "reference" values. The reference values are intended to replicate a competitive offer for the generator.[79] Use of the reference values allows energy market prices and payments to come

[73] Market Rule 1, Appendix A, Section 2.4.1

[74] Ibid.

[75] Market Rule 1, Appendix A, Section 5

[76] Economic withholding by generators refers to supply offers that exceed the short-run costs of committing and dispatching generators, in an attempt to avoid commitment or dispatch, increase energy market LMPs, and increase revenue available to a market participant. Under certain circumstances, elevated supply offers may represent an attempt to increase revenues to a market participant through increased uplift payments.

[77] The economic withholding rules are also supplemented by rules providing for the ex-post determination and referral of potential instances of physical withholding. Adequate rules to safeguard the market from physical withholding are important, as a physical withholding strategy can have the same negative impact on price formation as economic withholding.

[78] This review of supply offers is automated (along with the offer mitigation process), and occurs within the ISO's energy market software.

[79] The IMM estimates and maintains reference values for generators. See Market Rule 1, Appendix A, Section 7.

closer to approximating a competitive outcome, by limiting the ability of a market participant with market power to economically withhold energy from the market.[80]

11.2.1 Energy Market Mitigation Types

The IMM administers seven types of ex-ante energy market supply offer mitigation.[81] Appendix A of the ISO's Market Rule 1 outlines the circumstances under which the IMM may mitigate energy market supply offers.[82] These circumstances are summarized in Table 11-1 below.

Table 11-1: Energy Market Mitigation Types

Mitigation type	Structure test	Conduct test threshold	Impact test
General Threshold Energy (real-time only)	Pivotal Supplier	Minimum of $100/MWh and 300%	Minimum of $100/MWh and 200%
General Threshold Commitment (real-time only)		200%	n/a
Constrained Area Energy (import-constrained)	Constrained Area	Minimum of $25/MWh and 50%	Minimum of $25/MWh and 50%
Constrained Area Commitment (real-time only, import-constrained)		25%	n/a
Reliability Commitment	n/a	10%	n/a
Start-Up and No-Load Fee	n/a	200%	n/a
Manual Dispatch Energy (real-time only)		10%	n/a

For the ex-ante supply offer mitigation, the IMM applies up to three criteria when determining whether to mitigate a supply offer. The criteria are:

- **Structural test**: Represents a determination that market circumstances may confer an advantage to a supplier. This may result from (1) a supplier being "pivotal" (i.e., load cannot be satisfied without that supplier) or (2) a supplier operating within an import-constrained area (with reduced competition).

- **Conduct test**: Represents a determination that the financial parameters of a supply offer appear to be excessively high, relative to a benchmark offer value (a "reference" value).[83] The conduct test applies to all mitigation types.

- **Impact test**: Represents a determination that the original supply offer would have a significant impact on energy market prices (LMPs). This test only applies to general threshold energy and constrained area energy mitigation types.

[80] When an offer is mitigated, the reference values are used in both the market-clearing software and the settlement process (when applicable).

[81] Ex-ante mitigation refers to mitigation applied prior to the finalization of the day-ahead schedules and real-time commitment/dispatch.

[82] See Market Rule 1, Appendix A, Section III.A.5.

[83] See Market Rule 1, Appendix A, Section III.A.7, for the determination of reference values.

Supply offers are only mitigated when a violation of each applicable test occurs. For example, general threshold mitigation only applies when a supplier is pivotal, the offer prices for one (or more) of its generators exceed the conduct test thresholds, and the market impact of the economic withholding exceeds the impact test thresholds. The variation in tests across mitigation types reflects either market conditions associated with potential market power (transmission-constrained area vs. unconstrained area (general threshold)) or the likelihood that a participant's offers could directly impact uplift payments (e.g., reliability commitment and manual dispatch).

Finally, there is one additional mitigation type specific to dual-fuel generators not listed in Table 11-1 above. Dual-fuel mitigation occurs after-the-fact (ex-post) in cases where the supply offer indicated a generator would operate on a higher-cost fuel than it actually used (e.g., if offered as using oil, but the generator actually ran using natural gas). This mitigation will affect the amount of NCPC payments the generator is eligible to receive in the market settlements.

11.3 Capacity Market Mitigation

The IMM administers two forms of mitigation for Forward Capacity Auction (FCA) bids and offers: supplier-side mitigation for existing resources and buyer-side mitigation for new resources (i.e., the Minimum Offer Price Rules (MOPR) for new resources).

11.3.1 Supplier-Side Mitigation

A market participant attempting to exercise supplier-side market power will try to economically withhold capacity during the FCA – for a single year or permanently – in an effort to increase the clearing price above a competitive level. An inflated clearing price can benefit the remaining resources in the market participant's portfolio, as well as the portfolios of other suppliers.[84]

Delist bids are the mechanism that allow capacity resources to remove some or all of their capacity from the market for one or more commitment periods.[85] Delist bids specify the lowest price that a resource would be willing to accept in order to take on a capacity supply obligation (CSO). To restrict resources from leaving the market at a price greater than their competitive offers, the IMM reviews delist bids above a proxy competitive offer threshold called the dynamic delist bid threshold (DDBT) price.[86]

A competitive delist bid is consistent with the market participant's net going forward costs, expected capacity performance payments, risk premium, and opportunity costs. All existing capacity resources, as well as certain types of new import capacity resources, are subject to the

[84] A market participant would only attempt this if they believed (1) their actions would inflate the clearing price and (2) the revenue gain from their remaining portfolio would more than offset the revenue loss from the withheld capacity.

[85] Dynamic and static delist bids are both mechanisms to remove the capacity from existing resources from the FCA for a period of one year. The essential difference between the two is that static delist bids are at or above a certain price level that requires an IMM cost review.

[86] Delist bids priced below the DDBT are not subject to the IMM's cost review or mitigation; consequently, they are not discussed in this section. Market participants can dynamically delist resources if the auction price falls below the DDBT price. The DDBT has undergone a number of revisions since the start of the FCM.

pivotal supplier test.[87] If the IMM determines that a delist bid is uncompetitive and the supplier fails the pivotal supplier test, the IMM mitigates the delist bid to a competitive price (i.e., IMM's estimate of a competitive offer).

11.3.2 Buyer-Side Mitigation

ISO New England's buyer-side mitigation framework in the Forward Capacity Market applies only to new capacity resources that may artificially suppress prices due to out-of-market support. Resources below 5 MW, passive demand response, and those with no financial ties to load-serving entities or state-sponsored programs are exempt from mitigation. For all other new resources, the Internal Market Monitor conducts a case-by-case review to assess whether their participation would distort market outcomes.

11.4 Other IMM Monitoring and Potential Market Power Mitigation

The IMM also monitors the ISO's markets for other forms of potentially uncompetitive behavior. Several types of behavior or activities are specifically mentioned in the ISO's Tariff. These include:

- **Physical withholding**: Physical withholding involves participants attempting to influence market prices or other outcomes by physically withdrawing available capacity from the energy markets (e.g., false outage declarations or declining to make supply offers when it would have been in the participant's economic interest to do so).[88]

- **Physical supply offer parameters**: Physical supply parameters that are not subjected to limitation within the ISO's supply offer software (eMarket) can be reviewed by the IMM for potentially uncompetitive behavior and failure to comply with Tariff-prescribed limits. For example, an economic minimum offer is limited to being no more than double (100% greater than) the IMM's reference value; an economic maximum offer may be no less than 50% of its reference value.[89]

- **Increment Offers and Decrement Bids**: Deviations between day-ahead and real-time energy market LMPs are monitored to determine whether they are consistent with competitive outcomes. The IMM will review participant activities that might have contributed to these deviations and the role of increment offers and decrement bids in that activity.[90]

- **FTR Revenues**: The IMM monitors – and mitigates - the use of increment offers and decrement bids by the holders of financial transmission rights (FTRs). Increment offers

[87] A pivotal supplier controls sufficient supply such that the auction would be unable to meet its capacity requirement without that supplier's capacity. This condition potentially provides a supplier with sufficient market power to increase clearing prices. See Market Rule 1, Appendix A, Section 23.1 for a more precise definition of pivotal suppliers in capacity auctions. Note, the pivotal supplier test applies to static delists and the portfolio benefits test applies to retirements and permanent delists from the capacity market.

[88] Market Rule 1, Appendix A, Section 4.

[89] Market Rule 1, Appendix A, Section 6.

[90] Market Rule 1, Appendix A, Section 11.

and decrement bids can be used to create or magnify congestion that benefits the holders of FTRs.[91]

- **Cost of Service Agreements**: The IMM reviews the supply offers for generators that have cost-of-service agreements with the ISO.[92]

[91] Market Rule 1, Appendix A, Section 12.

[92] Market Rule 1, Appendix A, Section 14.