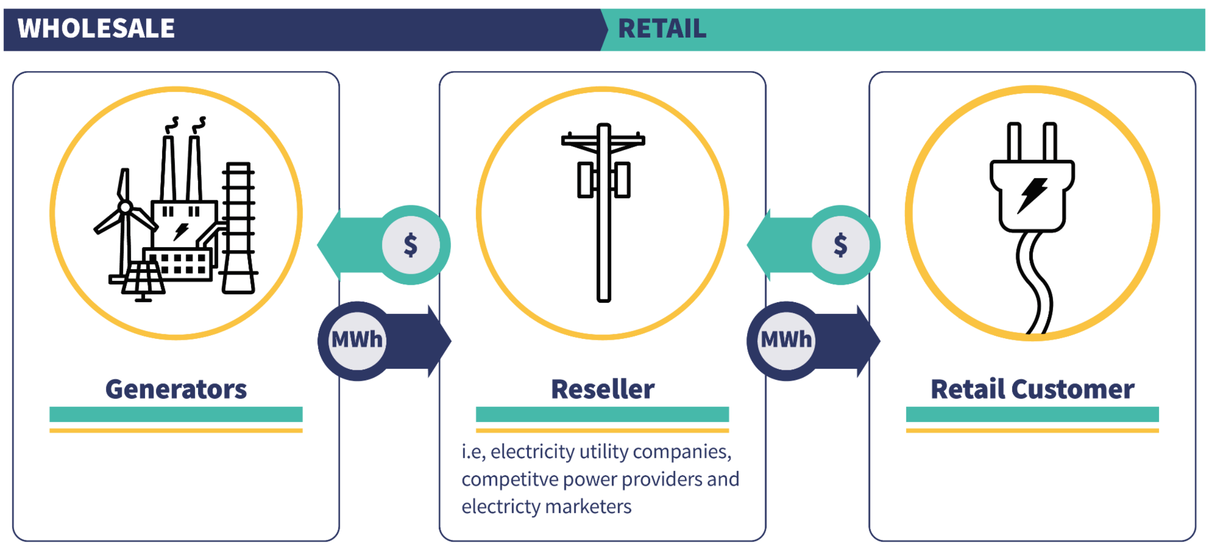
Overview of Forward Capacity Markets

Electricity markets in many regions of the United States are "deregulated," which means that different entities handle generation and distribution. That is, power plants ("generators") generate electricity and sell it to utility companies ("Load-Serving Entities," or LSEs), who then supply that electricity to end-use customers like houses and factories. The transactions between generators and LSEs typically occur through day-ahead and real-time auctions run by an **Independent System Operator** (ISO) or a **Regional Transmission Organization** (RTO). In this market, the relevant commodity is energy—that is, the actual physical electricity delivered to the grid.



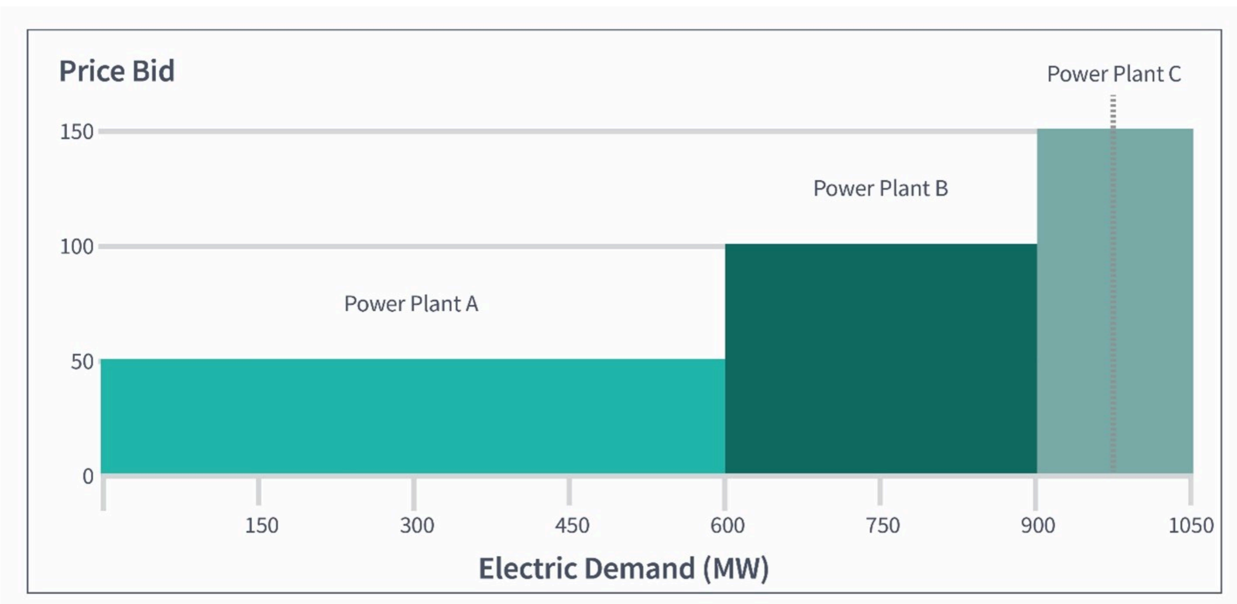
To help ensure sufficient supply, several ISOs and RTOs also operate **capacity markets**. In a capacity market, the commodity traded is not energy itself, but rather the *obligation to sell energy in the future if needed*. When a generator's bid clears a capacity auction, the generator receives a fixed payment in exchange for committing to be available during a future delivery period. Importantly, if called upon to produce electricity during that period, the generator's actual energy sales still occur through the day-ahead and real-time markets. Thus, the capacity market helps an ISO/RTO ensure that enough resources will be available to meet projected future demand.

The rest of this document explores capacity markets in more depth. Subsequent sections explain the rationale for capacity markets, the structure of capacity auctions, the resource accreditation process, and alternatives to capacity markets.

I. Why Do Capacity Markets Exist?

A central goal of ISOs and RTOs is to ensure that sufficient resources are available to meet expected electricity demand. In New England, for example, regulators generally require that the system maintain enough generation and demand-side capacity to limit the probability of a **loss-of-load event**—a situation in which demand exceeds available supply—to no more than one event in ten years.

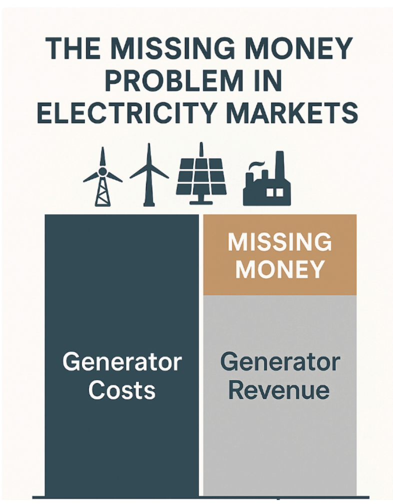
In the energy market, generators submit bids that specify both the quantity of energy they are willing to produce and the price at which they are willing to sell it. Grid operators then order these bids by price and draw on the cheapest units first. As a result, resources that are expensive to run and require high compensation—natural gas peaker plants, for example—will not be dispatched unless demand is unusually high. Because peak demand occurs only a few times per year, some expensive generators operate for very few hours annually, and other even-more-expensive generators may not run at all. Nevertheless, the system must ensure that these resources are available to meet demand during scarcity conditions and to cushion against unexpected demand spikes or supply disruptions.



In the above diagram, if ISO-NE wants to procure 1000 MW, ISO-NE would call on all three power plants and pay each $150 per MW. If only 900 MW are needed, ISO-NE would only call on Power Plants A and B, paying each $100 per MW. If ISO-NE rarely needs more than 900 MW on a given day, Power Plant C may rarely be called on (and will rarely receive revenue).

In theory, energy-only markets—where generators are paid solely for the electricity they produce—should provide sufficient incentives for these resources to remain online. This is because even though a given generator may run for only a few hours in the year, the price that it receives in those hours should theoretically be high enough to reflect the fixed costs of being online for the rest of the year. Indeed, several grids operate according to this principle. ERCOT in Texas, for example, used to let prices during scarcity conditions reach as high as $9,000 per MWh, which was supposed to incentivize both new investment in generation (to capture these higher prices) and demand-side response (to avoid paying these higher prices).

In practice, however, various constraints often prevent such pure price signalling. Many regions (including New England) have instituted energy price caps due to political pressure and the desire to protect consumers. Because price caps limit scarcity prices, expensive-to-run generators therefore cannot earn enough during rare high-demand periods to cover their fixed costs. This revenue shortfall, known as the "**missing money problem**," leads to underinvestment in generation and jeopardizes resource adequacy.



To solve the missing money problem, ISOs and RTOs such as ISO-NE have instituted **Forward Capacity Markets** (FCMs), which provide generators with fixed payments in exchange for a commitment to be available during future reliability events. These payments, determined by an auction held several years in advance, are supposed to make up the difference between the revenue required to stay online—i.e., the revenue that would be received absent price caps—and the actual revenue received given price caps. Thus, the FCM attempts to ensure that total compensation approximates what generators would earn in an unconstrained energy-only market.

FCMs also serve a planning function by signaling the need for new capacity. If expected supply falls below projected demand, market forces ensure that the fixed payments (clearing prices in the auction) grow larger, incentivizing investment in new generation. The capacity auction in New England has historically occurred three years before the "commitment period"—the time when generators receive payments and are expected to be dispatchable— to allow successful bidders to secure financing (eased by guaranteed payments) and construct new facilities before their obligation begins.

The following section explains how ISO-NE translates these abstract principles into practice.

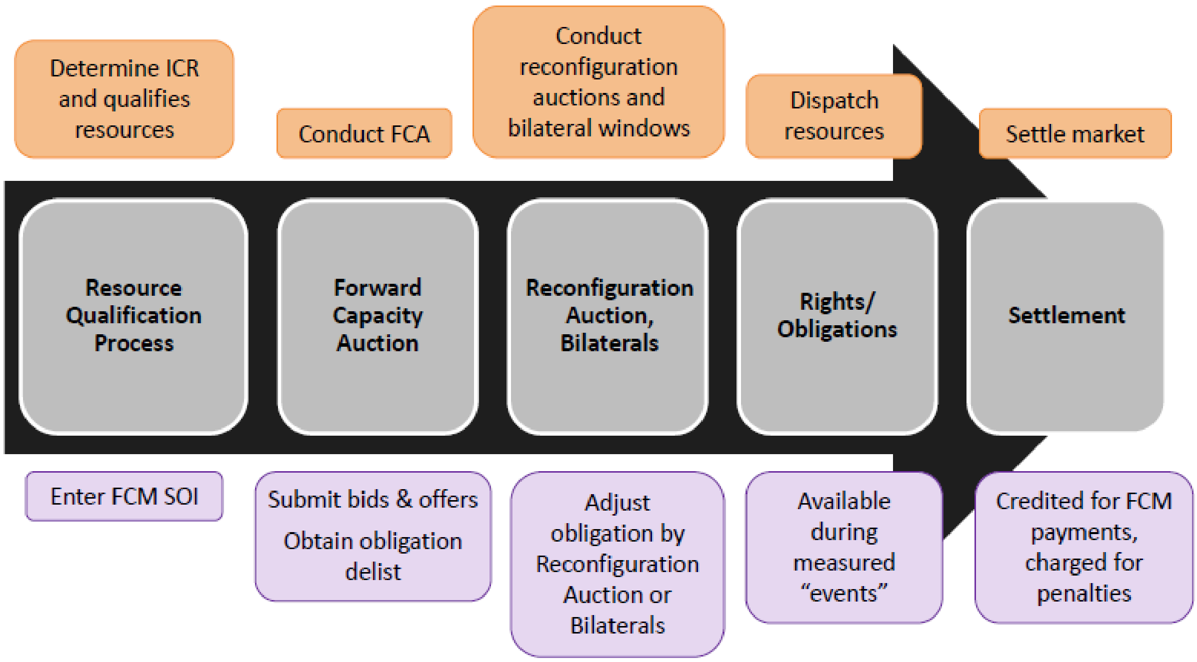
II. How Do Capacity Markets Work?

The first stage of a FCM is the **Forward Capacity Auction** (FCA). In ISO-NE, FCAs are held annually, three years before the start of the capacity commitment period. Prior to the auction, ISO-NE estimates the total amount of capacity required to satisfy resource adequacy criteria. This estimate, which is effectively the market's demand curve for capacity, was historically fixed, i.e., a vertical line in a supply and demand graph. In the 2010s, however, ISO-NE adopted a *sloped demand curve* that allows the auction to clear within a small range of capacity, in order to reduce year-to-year price volatility.

Once the FCA begins, qualified participants (called "qualified capacity resources," or QCRs) submit bids that specify the price at which they are willing to provide capacity. These qualified participants include not only generators but also demand-response entities that can reduce net load during peak conditions. ISO-NE then orders the bids by price, clearing the least-expensive bid until the capacity requirement is met. All cleared resources receive the price of the highest accepted bid under a uniform-price auction structure designed to reward low-cost resources.

Every participant that submits a clearing bid is awarded a **Capacity Supply Obligation** (CSO), which is a commitment to be available to supply electricity during the commitment period. Between the auction and the start of that period, ISO-NE monitors each resource's "critical path schedule" milestones (a development/upgrade roadmap) and may require demonstration of capability for new or upgraded resources. If a resource fails to meet readiness requirements, it must either shed its CSO or submit a restoration plan to regain compliance. During the commitment period, ISO-NE incentivizes compliance with CSOs during scarcity events through the **Pay For Performance** (PFP) system, which imposes penalties on generators that underperform and grants bonuses to those that exceed their obligations.

Finally, ISO-NE conducts a series of annual and monthly **reconfiguration auctions** between the initial FCA and the commitment period. These auctions allow the system to adjust total committed capacity in response to updated demand forecasts, and also enable participants to buy or sell CSOs to reflect changes in resource capability.



Source: Tianjiao Bao in "Solutions for the Resource Adequacy Issue in Alberta: Capacity Market, Scarcity Pricing, or Single Buyer Model"

III. What Is Resource Accreditation?

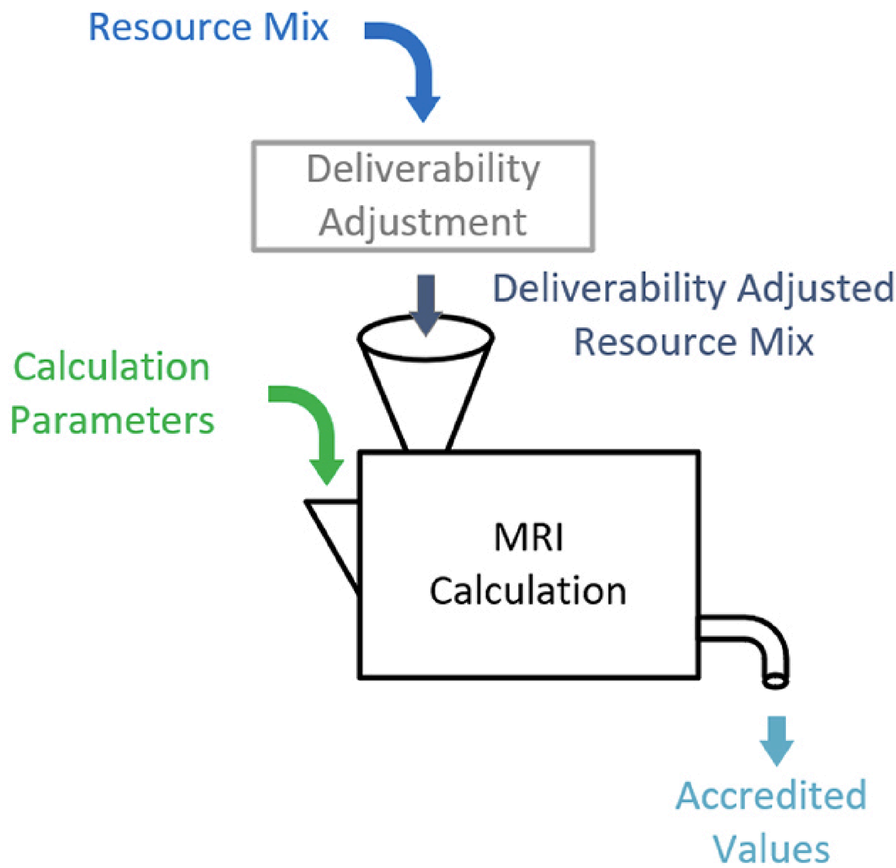
To maintain reliability and determine how much capacity to procure through the FCM, ISO-NE must accurately model the grid's ability to meet peak demand. Simply counting the total installed megawatts of generation, however, is not sufficient. Different types of resources contribute differently to reliability depending on their operating characteristics, fuel sources, and likelihood of being available when demand is highest. A gas turbine that can start up quickly at any time, for example, matters more for reliability than a solar farm that produces little energy on a winter evening, even though both might have the same nameplate capacity. As a result, a system that has ample nameplate capacity could still struggle to meet a demand spike if many of its resources are unavailable at the same time. ISO-NE therefore needs a framework to estimate each resource's reliable contribution to meeting demand that factors in a given resource's unique characteristics. This framework is called **resource accreditation**.

Resource accreditation determines how much **qualified capacity** each resource may offer into the FCA. Qualified capacity represents the portion of a resource's nameplate capacity that ISO-NE expects to be available during demand peaks, essentially measuring reliable rather than installed capacity. When ISO-NE considers whether it has procured enough supply to meet demand, it looks at qualified capacity and not nameplate capacity.

The qualified capacity of conventional thermal generators (gas, coal, oil, nuclear) is based on their **claimed maximum output** during peak demand conditions, known as **Seasonal Claimed Capability** (SCC). These resources can generally operate whenever needed, so they can usually be relied upon to generate electricity during scarcity conditions. As such, qualified capacity for thermal generators is typically very close to nameplate capacity, which results in relatively high capacity revenues and thus a greater incentive for investment. Importantly, however, this value does *not* currently reflect thermal generators' forced-outage rates and fuel supply limitations.

Intermittent resources (wind, solar) are accredited very differently. Their qualified capacity is based on historical median performance during pre-defined **reliability hours**—periods when demand is high and the system is most stressed. This formula reflects the intermittency of these resources; it is irrelevant that a solar farm can theoretically supply 100MW if it can only supply 30MW during demand peaks. Qualified capacity for wind and solar, then, is typically a fraction of nameplate capacity. The current resource accreditation framework thus strongly favors dispatchable resources like natural gas.

Another, more sophisticated approach to resource accreditation—the one that ISO-NE is proposing to enact through its Capacity Auction Reforms (CAR) initiative—is marginal **Effective Load Carrying Capacity** (ELCC). To find a given resource's qualified capacity (called **Marginal Reliability Impact** (MRI)) with ELCC, ISO-NE would run a probabilistic model simulating future outages given expected weather, resource supply (including the specific resource in question), and energy demand, tweaking the supply and demand parameters until the desired reliability (one-in-ten loss of load) is reached. Then, ISO-NE would remove the specific resource and add perfectly-available capacity until the desired reliability is again reached. The amount of perfectly-available capacity added is the specific resource's qualified capacity. In simpler terms, ELCC measures the amount of additional load the system could serve with the resource (versus without it), while meeting the same target number of loss of load events. Ideally, this approach would also capture the fact that the reliability value of additional capacity declines as more of the same resource is added. For instance, once a large solar fleet is already meeting daytime demand, each new megawatt of solar provides progressively less reliability benefit, since those hours are no longer at risk.



Source: ISO-NE

IV. Alternatives to Capacity Markets

While capacity markets are currently the dominant mechanism for ensuring reliability in several U.S. regions, they are not the only approach. Other systems rely on energy-only markets or bilateral contracting to ensure that enough generation is available to meet demand.

An **energy-only market** (EOM) relies solely on revenues from energy and ancillary services to fund investment. There is no separate capacity payment; instead, high scarcity prices during tight supply intervals signal the need for new investment and demand-response, while also compensating for flexible resources. Texas' ERCOT system, for example, has historically allowed prices to rise as high as $9,000 per MWh, sending a strong signal that results in reasonable levels of reliability (although ERCOT has since instituted a price cap). Proponents argue that this approach achieves reliability through pure price incentives, avoids the administrative complexity of capacity markets, and keeps consumers from giving extra revenue to resources that would have stayed online even absent capacity payments. Critics note, however, that high scarcity prices can be incredibly unpopular, leading to price caps that undermine the foundation of the system. Additionally, regulators' target resource adequacy level (1-in-10 loss of load expectation) is likely below the economically efficient level, so an energy-only market might result in a higher incidence of loss of load events than is politically acceptable. Moreover, ERCOT's fatal failure to ensure resource adequacy during Winter Storm Uri (2021) has led many (including legislators and regulators) to call for a capacity market-esque system in Texas.

Other regions maintain reliability through **bilateral capacity contracts**. In these systems, load-serving entities are generally required to procure sufficient capacity through long-term contracts with generators. Alternatively, some regions where utilities are *vertically integrated*—i.e., where a single utility owns generation, transmission, and distribution infrastructure—require utilities to plan to build sufficient generation through **Integrated Resource Plans** (IRPs). The Western U.S. and much of the Southeast follow variants of this approach. Advantages include price stability, long-term investment certainty, and the ability to tailor procurement to local policy goals like renewables targets. The downside is that these systems limit competition, forcing regulators to make complex judgments about which resources to build or retain. These human decisions can be less efficient than market outcomes, especially given how understaffed some public utilities commissions are.

History of ISO-NE's Forward Capacity Market

ISO New England ("ISO-NE"), the organization responsible for managing the region's electric grid, operates a Forward Capacity Market ("FCM") that pays power plants for committing to be available to supply energy during a future period.[1] Since the establishment of the FCM in 2006, ISO-NE has struggled to balance two objectives:

1. Ensuring resource adequacy, i.e., making sure that enough generators (power plants) will be available to meet future projected energy demand; and
2. Maintaining affordability by not overpaying generators.

These goals are naturally in tension. The FCM attempts to ensure resource adequacy by compensating generators to stay online, but those payments are passed on to consumers like homes and factories, raising electricity prices. And when the market's incentives become misaligned, as has often happened, it can fail on both fronts by overpaying generators without improving reliability.

Building on our overview of capacity markets, this document details how ISO-NE has iteratively redesigned its FCM to better balance these two aims. We start with the leadup to the FCM and the reasons why such a system was chosen. We then survey the early years of operation, examine major changes to the market's structure in the 2010s, and finish with recent reforms that set the stage for the Capacity Auctions Reform project.

[1] For background on how capacity markets work, see our earlier "Overview of Forward Capacity Markets." The rest of this document presumes some basic knowledge of capacity markets.

Key Milestones in ISO-NE Forward Capacity Market (1998–2024)		
Year(s)	**Auction(s)**	**Reform or Outcome**
1998	N/A	ISO-NE begins operating a bid-based market for installed capacity.
2004	N/A	ISO-NE proposes a LICAP market to ensure reliability; eventually rejected by FERC.
2006	N/A	FERC approves Devon Power settlement to create a Forward Capacity Market (FCM).
2008–2013	FCA 1-7	Capacity prices remain low and close to price floors, signaling high energy supply.
2013	FCA 7	NEMA/Boston zone clears much higher than the overall system, suggesting local scarcity.
2014	FCA 8	Just before FCA 8, ISO-NE declares a shift from capacity surplus to shortage due to large retirement; asks FERC for higher admin prices.
2015	FCA 9	Sloped demand curve replaces fixed vertical construct; price volatility declines.
2016	FCA 10-11	Zonal demand curves adopted to reflect local transmission constraints.
2018	FCA 12	Pay-For-Performance becomes effective (FERC-approved 2014); CASPR accepted.
2019	FCA 13	Only 54 MW clear in the CASPR substitution auction.
2020	FCA 14	Record-low clearing price. FERC later orders removal of the new-entrant price lock rule.
2022–2024	FCA 17-18	MOPR phased out; full removal with FCA 19, paving the way for CAR reforms.

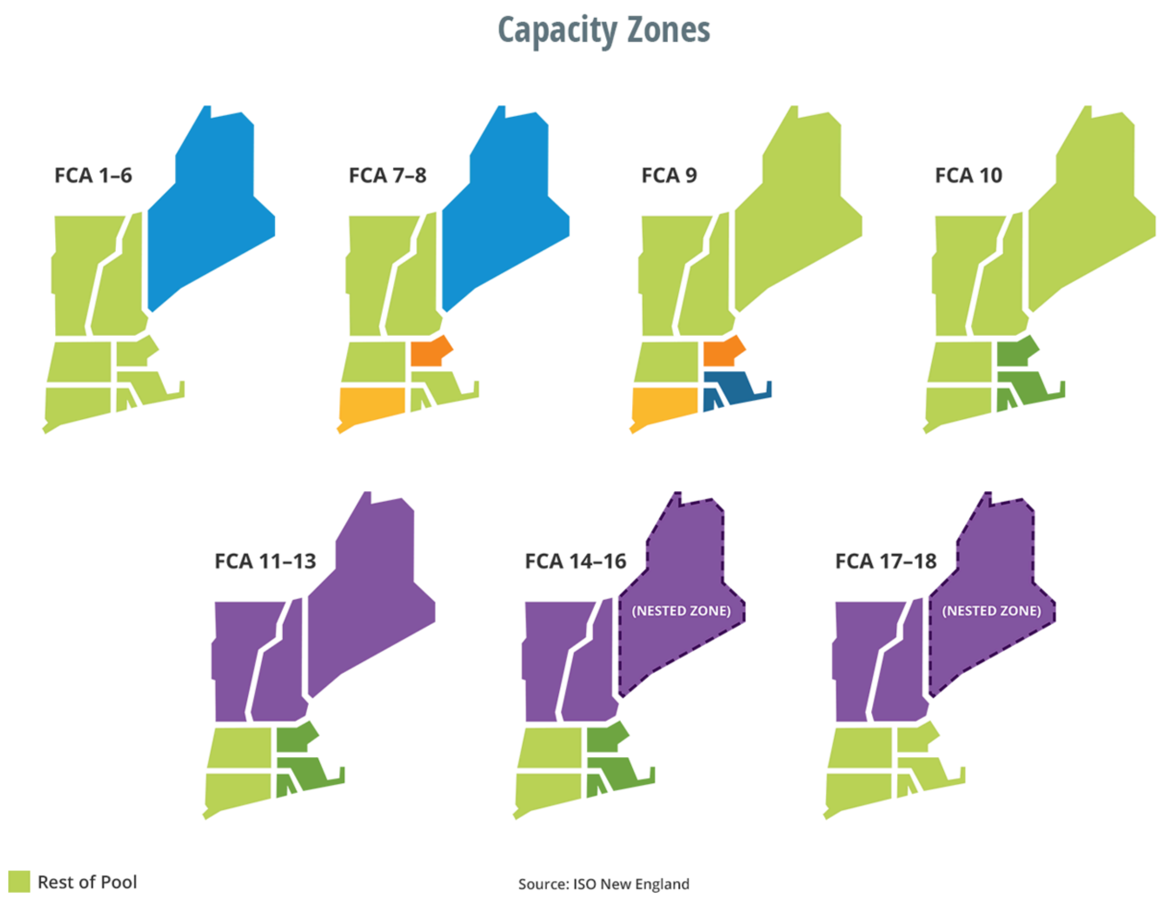
I. The Creation of the Forward Capacity Market

In 1998, ISO-NE began operating a market for installed capacity ("ICAP"). This market required load-serving entities—utility companies that buy electricity from generators and deliver it to customers—to procure enough capacity to meet projected demand plus a reserve margin.

Over time, however, the ICAP market proved inadequate in several ways. Most importantly, it lacked a *locational* element: because it did not distinguish between densely and sparsely populated areas, it could not guarantee that electricity would be available where it was most needed. Transmission lines have finite capacity, so a subregion can only import a limited amount of power from elsewhere. As a result, even if New England as a whole produced enough electricity to meet total demand, shortages or blackouts could still occur when most generation was located in Maine but most consumption was in Massachusetts. A well-designed system would have incentivized more investment in an import-constrained area like Massachusetts, rather than blindly paying the same amount for capacity everywhere. But ICAP did not, so to ensure that needed power plants in these threatened subregions stayed online, ISO-NE had to increasingly rely on expensive reliability-must-run ("RMR") contracts, where it directly paid generators enough to keep them afloat.

Recognizing this problem, FERC ordered ISO-NE to reform its capacity procurement system to make it more location-sensitive in 2003. In response, ISO-NE proposed the Locational Installed Capacity ("LICAP") system in 2004, which included monthly auctions for capacity and locational pricing. FERC conditionally accepted LICAP but deferred implementation until 2006 to allow time for refinement. As the record developed, however, states and consumer advocates began to project that LICAP could sharply raise capacity prices in the near term, which encouraged parties to search for less costly alternatives.

That search produced the Forward Capacity Market. In 2006, through the *Devon Power* settlement, FERC approved a contested agreement that replaced LICAP with the FCM. The settlement made three crucial changes. First, it introduced a forward, annual auction—the Forward Capacity Auction ("FCA")—held three years before the delivery year, which was intended to give developers a firm price signal and time to build capacity to fulfill obligations. Second, it retained locational requirements through import- and export-constrained zones, which addressed the geographic adequacy problem that had plagued ICAP. Third, it mandated fixed transition payments for generators from 2006 to 2010 to bridge the gap until the first commitment period could occur.



II. The Early Market and the Sloped Demand Curve

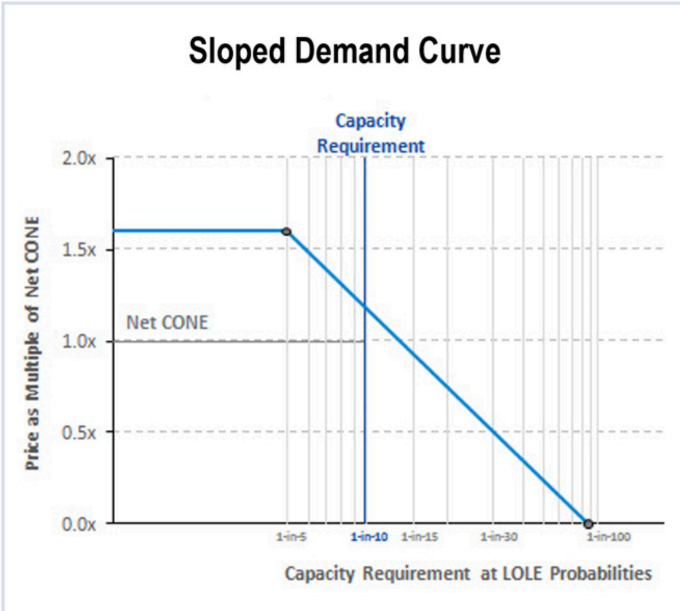
For the first seven years of the FCM's operation, New England had a surplus of capacity. As a result, the FCA generally cleared near its administratively set price floor, which was calculated as a percentage of the "Cost of New Entry" (CONE)—the estimated cost of building new, eligible generation.

Importantly, ISO-NE used a fixed Installed Capacity Requirement (ICR) to determine how much capacity to purchase in each auction. The ICR represented the total amount of generation the system needed to meet forecasted demand plus a reserve margin. Because this requirement was fixed (a "vertical" demand curve), ISO-NE was obligated to buy exactly that amount of capacity regardless of cost in each FCA. This design made auction clearing prices extremely sensitive to small changes in supply (the amount of power plants entering the auction and the size/prices of their bids). This is because the FCA cleared at a *uniform price*: ISO-NE accepted the lowest-cost bids until the ICR was met and paid every accepted generator the price of the highest accepted bid. Consequently, even just a few generators retiring could force ISO-NE to accept much more expensive bids, drastically raising the price of *every* cleared bid; and a few new entries could just as easily swing prices in the opposite direction. Either outcome was destabilizing: high prices were politically untenable, and low prices discouraged investment. Therefore, to temper this volatility, ISO-NE instituted price floors and price caps, and reserved the right to administratively (i.e., centrally) set clearing prices when market conditions failed to produce a competitive outcome.

These administrative pricing provisions were first triggered in FCA 7 (2013), when ISO-NE found insufficient competition in the Northeast Massachusetts/Boston ("NEMA/Boston") region and cleared that subregion at a much higher price than the rest of New England. The system-wide price, however, remained near the price floor, illustrating how local scarcity can easily coexist with regional surplus due to transmission constraints.

Shortly before FCA 8 (2014), however, a wave of power plant retirements flipped the region from surplus to shortage. The possibility of prices spiking far above historical levels—driven by the fixed ICR's knife-edge price response—heightened concerns about volatility and price shocks, prompting regulators to look for a long-term structural solution.

This solution was a *sloped demand curve*. While the fixed ICR had been a vertical curve since ISO-NE required the same amount of capacity regardless of price, the sloped demand curve adjusted capacity requirements based on price. That is, ISO-NE procured capacity within a range, buying more when prices were low and less when prices were high. This approach smoothed price volatility, dampened the effects of a few units retiring, and thereby reduced the need for administrative pricing. FERC approved the sloped demand curve in 2014, and ISO-NE first implemented it in FCA 9. Two years later, in FCA 11 (2016), ISO-NE expanded the design to include zonal demand curves for each import- and export-constrained region.



(Source: ISO-NE)

III. Shortages and Pay-For-Performance

The winter of 2013–2014 exposed a mounting reliability crisis in New England. Even though the FCM consistently procured sufficient capacity on paper, the region nevertheless experienced repeated supply shortfalls, largely because weak penalties for non-performance incentivized generators to underperform on their obligations to deliver energy. That is, many generators that were being paid to remain "available" were unable or unwilling to deliver energy during scarcity events. Even more, many natural gas plants—the dominant resource in New England—often lacked firm fuel contracts or stored reserves; they were simply not *prepared* to supply energy.

Under the FCM's original design, resources had few incentives to ever actually deliver energy or maintain readiness. Generators that cleared the FCA received capacity payments for committing to be available, but there was no systematic mechanism to reduce those payments if they failed to follow through on that commitment. As ISO-NE later explained, the market was "paying for promises, not performance." Indeed, given the cost of securing fuel and maintaining reserves, it was often more profitable for many resources to not even prepare to deliver energy; as long as they passed ISO-NE's readiness checks, they could collect capacity payments at no cost, wasting ratepayer money and threatening grid reliability.

In 2014, FERC ordered ISO-NE to reform its FCM payment design and tie compensation to actual energy delivery during scarcity conditions. ISO-NE responded by proposing the **Pay-For-Performance** (PFP)framework, which FERC approved that year. PFP, still in use today, divides capacity compensation into two parts: a base capacity payment, earned simply for holding a Capacity Supply Obligation (CSO), and a performance payment that applies only during defined scarcity conditions. During such events, ISO-NE compares each generator's output to its share of system load promised in its Capacity Supply Obligation (CSO). Resources that overperform earn a bonus, while those that underperform pay a penalty. These penalties and bonuses are internally redistributed—i.e., one generator's penalty funds another's bonus—to make the system ratepayer-neutral. The system therefore incentivizes generators to actually deliver energy, ensuring reliability and ratepayer affordability.

IV. MOPR and CASPR

In 2013, ISO-NE implemented a Minimum Offer Price Rule (MOPR), enforced through "Offer Review Trigger Prices" (ORTPs). The MOPR set a floor for bids in the FCA, preventing new generators from bidding below what ISO-NE deemed their "net cost of new entry": the minimum price needed to recover their costs absent any subsidies. This did not apply to existing generators.

The rule was intended to mitigate predatory buyer behavior. Regulators worried that a utility company could sign side contracts with certain generators to pay a share of the expected FCA profits, allowing these generators to bid artificially low in the FCA. This would push down the market's clearing price, so the overall costs of the FCA would decrease and less would be passed on to the utility. Thus, the utility could actually profit by subsidizing a subset of the FCA's participants. Such artificially low prices, however, would send distorted investment signals and undermine long-term reliability by discouraging new entry.

But over time, the MOPR proved harmful for state renewable agendas. As states began subsidizing wind, solar, and other clean resources to meet emission-reduction goals, those resources entered the FCA with costs partially offset by state support. Yet under the MOPR, they were still required to bid at or above their unsubsidized ORTPs, which were typically higher than bids from existing fossil-fuel generators. As a result, most state-sponsored renewables could not clear the auction and compete with fossil fuels, even though their effective, subsidy-adjusted costs were competitive. The MOPR thus excluded many clean-energy projects from capacity revenues and limited states' ability to integrate their policy-supported resources into ISO-NE's markets.

To address this, ISO-NE introduced Competitive Auctions with Sponsored Policy Resources (CASPR) in 2018. CASPR added a secondary "substitution" auction immediately after the FCA, in which generators who had won CSOs but wanted to exit the market could sell their CSOs to generators who had not. There was no MOPR in this substitution auction. The intent was to allow state sponsored resources to bid at their true cost—accounting for the state subsidies—in the substitution auction and buy CSOs off non-sponsored resources, which would accommodate state renewable agendas without distorting prices in the primary auction.

In practice, CASPR turned out to be largely ineffective. In the first substitution auction (FCA 13, held in 2019), only 54 MW cleared, compared to roughly 35,000 MW in the primary auction. This was largely because only resources that wanted to permanently retire from the market could sell CSOs in the substitution auction, and not many such resources existed. ISO-NE, then, still needed a way to better allow for state renewable aims.

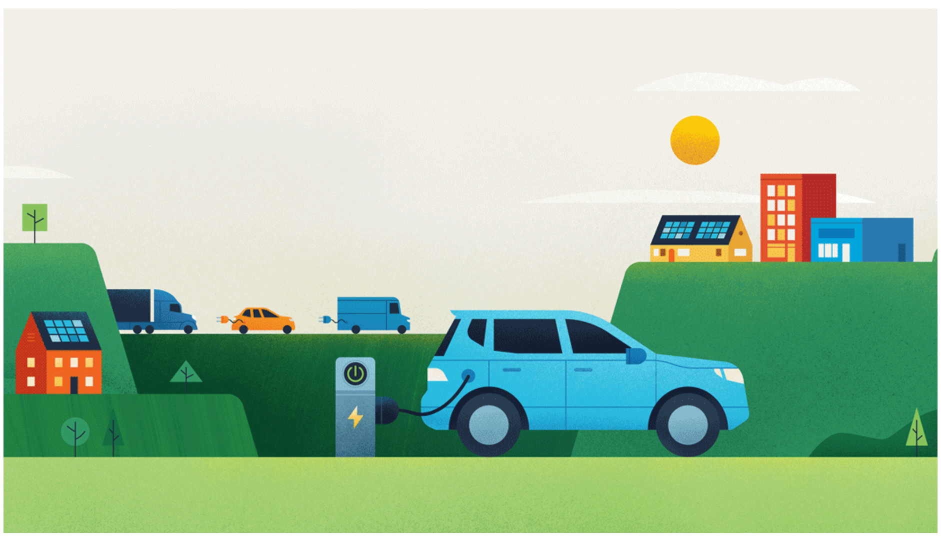
This way ended up being the elimination of the MOPR. In May 2022, FERC approved an ISO-NE plan to allow broad exceptions to the MOPR for FCA 17 and FCA 18, and to eliminate it entirely beginning with FCA 19. As of October 2025, FCA 19 has not yet occurred; it will mark the first capacity auction conducted under ISO-NE's forthcoming Capacity Auction Reforms (CAR) framework, completing nearly two decades of iterative market redesign.

Overview of Capacity Auction Reforms (CAR)

ISO New England's **Capacity Auctions Reform** (CAR) project is the most comprehensive redesign of the region's Forward Capacity Market (FCM) since its creation in 2006.[2] ISO-NE argues that the current market structure, which was developed under very different system conditions, no longer meets the needs of today's grid. CAR therefore proposes a set of interrelated reforms intended to align the market with a rapidly changing resource mix and evolving reliability risks.

First, CAR replaces the existing forward capacity auction, held three years in advance of the delivery period, with a prompt auction conducted 1-2 months ahead. To facilitate this shift, ISO-NE also proposes new procedures for resource retirements and deactivations. Second, the reforms would change the structure of capacity commitments from annual to seasonal. Third, ISO-NE seeks to update the resource accreditation process to better measure the reliability contributions of renewable energy.

The remainder of this memo describes each of these components in detail and explains ISO-NE's stated rationale for pursuing them.



[2] This work assumes some familiarity with ISO-NE's current Forward Capacity Market. We recommend reading our previous two works before this one, namely, "Overview of Forward Capacity Markets" and "History of ISO-NE's Forward Capacity Market."

I. From Forward to Prompt Capacity Auctions

In New England, capacity auctions have historically taken place three years before the "commitment period"—the time when generators begin receiving payments and are expected to be available to produce electricity. That is, a new generator that clears the Forward Capacity Auction (FCA) is not required to deliver energy until three years later. This long lead time was intended to make it easier for new power plants to secure financing. By clearing the Forward Capacity Auction (FCA) before construction, a developer could show investors a guaranteed stream of future payments from the Forward Capacity Market (FCM) and use that assurance to raise capital. When the system was created, most new resources were natural gas plants, which could typically be built in less than three years. The expectation was that these generators would complete construction and be ready to deliver power by the start of their commitment period.

Now, however, CAR is proposing to move the capacity auction such that it takes place 1-2 months before the commitment period. ISO-NE offers several reasons for doing so.

1. *Improving ISO-NE's Forecast Accuracy.* When ISO-NE decides how much capacity to buy through the capacity market, it must estimate future electricity demand and set its procurement targets to satisfy that amount. This process, however, relies on forecasts of many uncertain factors, like generator retirements, changes in demand, weather patterns, fuel prices, and state energy policies. Because these factors are difficult to predict three years in advance, ISO-NE plans conservatively and procures enough capacity to cover the worst-case scenario. In practice, however, this approach often results in buying more capacity than the system ultimately needs, and so consumers end up paying for capacity that is never necessary. Shifting to a prompt auction months before the commitment period is supposed to resolve this issue, since ISO-NE can use more accurate information in its forecasts, reducing the risk of overprocurement.

2. *Improving Generators' Forecast Accuracy*. A version of the same forecasting problem affects generators too. When deciding what price to bid for a Capacity Supply Obligation (CSO), a generator must estimate its expected costs during the future commitment period. A key concern is the possibility of failing to deliver as promised, which can lead to substantial fines under ISO-NE's Pay For Performance (PFP) system. To account for this risk, generators build a margin of safety into their bids and demand higher payments to compensate for potential penalties. Because the commitment period begins three years after the Forward Capacity Auction, generators face considerable uncertainty about future fuel prices, maintenance needs, and plant availability. As a result, they tend to include a larger "risk premium" than might be

necessary if those conditions were known. A prompt auction—held much closer to the delivery period—would reduce that uncertainty, allowing generators to bid more confidently and potentially lowering overall costs to consumers. A prompt auction would also align more closely with natural gas plants' fuel delivery schedules; contracts for the winter are often formed in the preceding summer, not three years prior.

3. *Reducing Phantom Capacity*. Because the current market has a three-year lead time, new projects are allowed to participate before construction begins. That is, they are not required to show that they can actually generate electricity at the time of the auction. As such, it's possible (and common) for a project to clear the capacity auction—and thereby lower the clearing price—but fail to be in service by the delivery period for logistical reasons, which distorts price signals and poses reliability concerns. The prompt auction, however, would require resources to demonstrate capability before bidding, avoiding this concern.

II. Changes to Resource Retirement Rules

Under the current market design, a generator that wishes to exit ISO-NE's market must do so through the Forward Capacity Auction. Three years before the intended retirement date, the generator submits a "de-list" bid specifying the minimum price at which they are willing to continue participating. If the FCA clears below that price, the generator may retire. However, if ISO-NE determines that this unit is needed for reliability, it can be retained via an out-of-market agreement until a replacement is available

As part of CAR, ISO-NE proposes to separate retirement from the auction entirely. In a prompt market, auctions would occur only a few months before the delivery period, and so it would be impossible for bids to serve as advance retirement signals. The shift to a prompt framework therefore requires a new process for generators to declare their intent to retire.

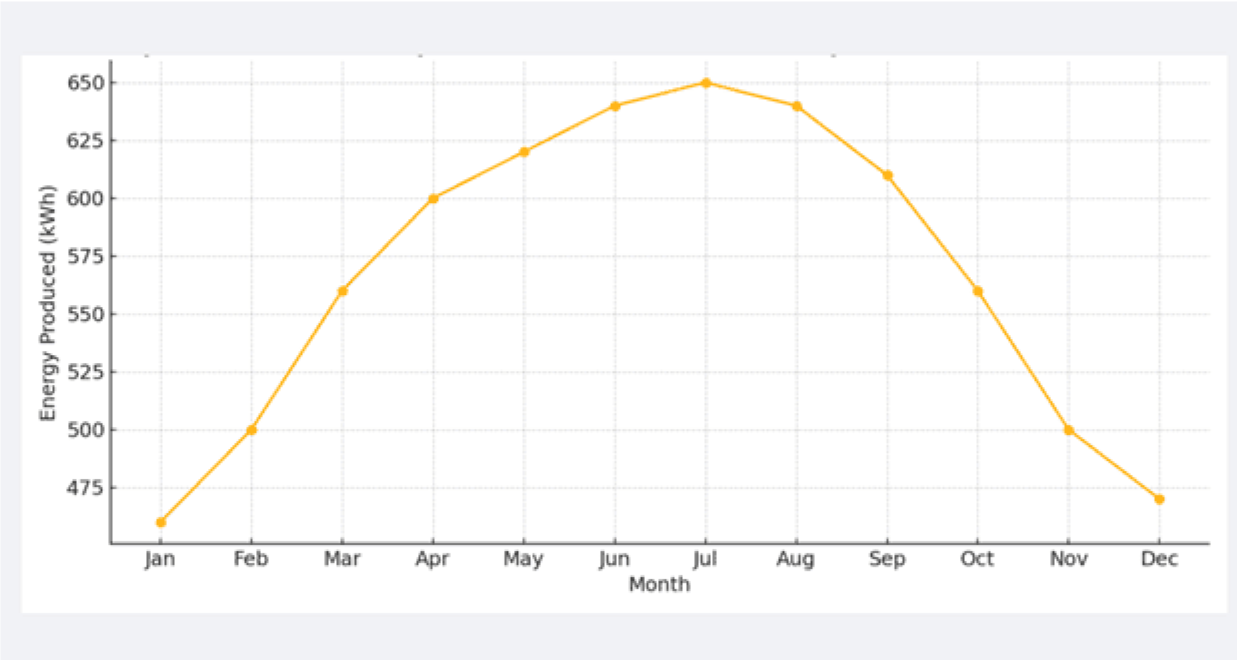
Under the proposal, generators would instead submit formal deactivation notices one year before their desired retirement date. This notice period would give ISO-NE time to assess whether the unit is needed for reliability and, if so, arrange temporary retention under existing reliability provisions. The shorter, one-year window also allows owners to make decisions based on more up-to-date information, reducing the likelihood that they initiate retirement plans and later reverse course as market conditions change.

III. From Annual to Seasonal Commitment Periods

ISO-NE's Forward Capacity Market currently procures capacity for a single annual commitment period: generators bid for and receive obligations to supply electricity for an entire year. ISO-NE is now proposing to replace this annual structure with a seasonal one, in which the market would procure capacity separately for the summer (May 1–October 31) and winter (November 1–April 30) through distinct auctions.

ISO-NE argues that an annual commitment period masks large seasonal differences in reliability risk. In New England, winter reliability risks generally arise because natural gas—by far the dominant resource—is fuel-constrained in the winter, as heating requires natural gas and takes precedence over power generation. As a result, some important generators may be unable to obtain fuel during cold spells. Summer risks, meanwhile, are driven by extreme heat and the resulting surge in air-conditioning demand. Solving these distinct problems requires different types of resources; diversifying from natural gas to protect against winter risks may result in a resource mix that isn't operational during summer peaks, for example, and vice versa. Because the annual auction must cover both sets of risks, ISO-NE typically plans for the most demanding conditions in either season, effectively procuring for the "worst case." That approach ensures reliability but tends to overbuy capacity, which raises costs for consumers.

By contrast, ISO-NE contends that seasonal commitment periods would allow the market to procure capacity that matches the timing of need. Importantly, ISO-NE could purchase more non-gas generation during the winter, and then *not* pay them to be online in the summer when they're less necessary. The market could more accurately value commitments from solar resources more highly in the summer, when daylight abounds, than during the winter.



Seasonal variation in solar output. Source: Solaris Renewables.

To further account for winter fuel limitations, ISO-NE has proposed introducing a "Winter Gas Constraint." Under this rule, the market would procure only up to a specified share of winter capacity from natural gas generators, on the grounds that gas generators cannot reasonably be expected to (as a whole) procure more than a certain amount of gas fuel. Gas generators would compete with each other in the capacity auction for shares of this pie during the winter capacity commitments, and the remainder of capacity needs would be met by other technologies.

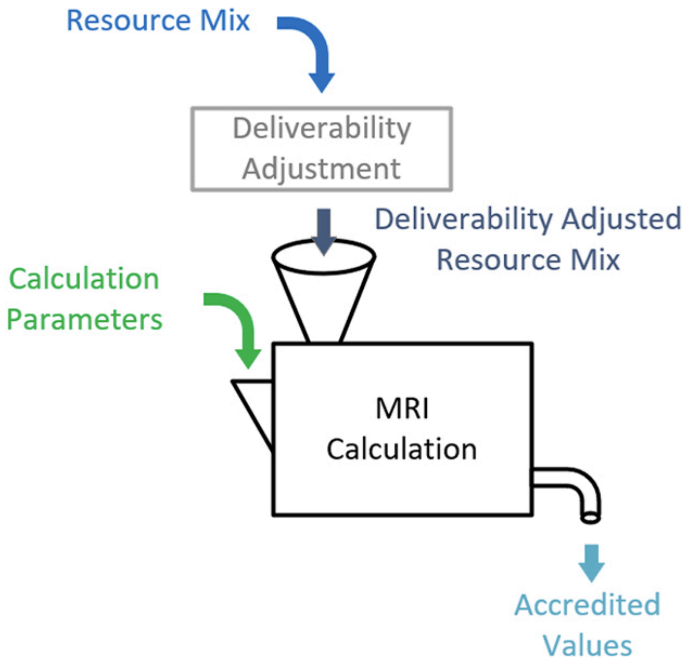
IV. Reforming Resource Accreditation

Resource accreditation is the process by which ISO-NE estimates how much a given generator can contribute to system reliability. This is usually different from a generator's nameplate capacity—the maximum it can produce under ideal conditions—since what matters for reliability is whether a resource can contribute when the system is under stress. A solar farm that can produce 100 MW of energy on a summer afternoon, for example, may contribute little on a winter evening demand peak. Importantly, in the capacity market, resources are paid based on their accredited (qualified) capacity, not nameplate.

Today, dispatchable resources—those that can be turned on at any point, like gas, coal, oil, and nuclear—are accredited based on their claimed maximum output during peak demand conditions, so their qualified capacity is typically close to their nameplate capacity. Meanwhile, intermittent resources—those that can only sometimes deliver energy, like wind and solar—are accredited based on their historical median performance during pre-defined hours of system scarcity. Because these scarcity hours often don't align with solar/wind peaks, qualified capacity for these resources tends to be much lower.

However, ISO-NE has recently pointed out several problems with this approach. First, it does not account for winter fuel limits: gas plants can be unable to obtain fuel and thus cannot run. Second, when one gas generator is forced offline, other gas generators elsewhere are also likely to be forced online (a *correlated* outage), because fuel constraints in one power plant imply fuel constraints elsewhere. But simply saying that a given gas generator has an X% chance of turning off at any given moment therefore underestimates the risk of a large segment of gas generation simultaneously turning off, which is much worse from a reliability perspective. Third, this approach doesn't model the fact that intermittent resources like solar face diminishing marginal returns. Once a large solar fleet is already meeting daytime demand, for example, each new megawatt of solar provides progressively less reliability benefit, since those hours are no longer at risk. As renewables continue to grow, this last limitation becomes more pertinent.

CAR therefore proposes replacing the current method with a marginal, reliability-based methodology called marginal Effective Load Carrying Capacity (ELCC). To find a given resource's qualified capacity (called Marginal Reliability Impact (MRI)) with ELCC, ISO-NE would run a probabilistic model simulating future outages given expected weather, resource supply (including the specific resource in question), and energy demand, tweaking the supply and demand parameters until the desired reliability (one-in-ten loss of load) is reached. Then, ISO-NE would remove the specific resource and add perfectly-available capacity until the desired reliability is again reached. The amount of perfectly-available capacity added is the specific resource's qualified capacity. In simpler terms, ELCC measures the amount of additional load the system could serve with the resource (versus without it), while meeting the same target number of loss of load events. In theory, since the simulation is run on a resource-by-resource basis, this should avoid the above problems.



Source: ISO-NE

V. Governance in the Capacity Auction Reforms Process

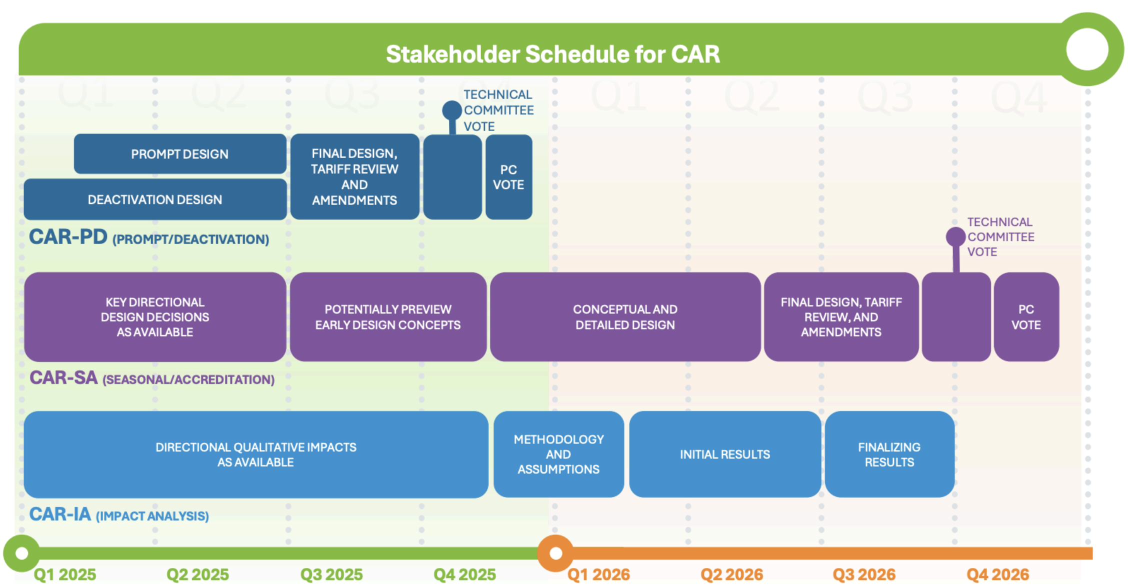
One important benefit of understanding these reforms is the ability to provide better-informed feedback to ISO-NE. To that end, this section first outlines how governance in ISO-NE operates at a broad level, then describes the opportunities for stakeholder input specifically within the CAR process.

ISO-NE is formally responsible for administering the region's wholesale electricity markets and proposing changes to the Federal Energy Regulatory Commission (FERC). Although ISO-NE retains the authority to file tariff (market rule) changes unilaterally, it almost always develops them through the New England Power Pool (NEPOOL), a stakeholder organization representing utilities, generators, suppliers, consumer advocates, and state officials.

In practice, ISO-NE staff first propose changes to NEPOOL's technical committees (Markets, Reliability, Transmission, and various subcommittees), which review proposals, provide feedback, and suggest revisions. Once these committees have completed their work, proposals advance to the NEPOOL Participants Committee, which is the organization's primary decision-making body. Here, different market participants—organized by sector, with each sector receiving an approximately equal share of votes—debate and vote on whether to recommend the changes. If NEPOOL accepts, ISO-NE and NEPOOL jointly file the proposed tariff revisions with FERC, which has the final authority to accept or reject them. If NEPOOL refuses, ISO-NE can still file revisions unilaterally, but FERC—with the knowledge that the changes lack stakeholder approval—is more likely to reject them.

Although this process is seemingly democratic, it has been criticized for giving ISO-NE staff and large entities undue influence. ISO-NE staff do not vote in NEPOOL, but retain practically decisive authority because they draft detailed technical proposals, set timelines, and control the modeling/assumptions that drive the discussion. As such, many stakeholders feel that the ISO's technical framing strongly shapes outcomes. Meanwhile, most entities have "grouped" votes—i.e., collectively count as one vote—but entities past certain investment or MW thresholds have "individual" voting power, and so larger entities generally have much more sway in NEPOOL votes. In addition, small players in practice often lack the modeling resources, legal staff, or the coalition scale of incumbents to shape detailed technical design or even keep up with sophisticated market proposals, further limiting influence. Finally, this process is generally quite slow; major reforms can take years, which slows down responses to a rapidly evolving energy landscape.

CAR is following this process. ISO-NE has separated the process into two stages: CAR-PD (Prompt/Deactivation) shifts from a forward to a prompt market and, accordingly, implements deactivation changes; and CAR-SA (Seasonal/Accreditation) shifts from an annual market to seasonal one and modifies resource accreditation rules. Although the ISO and NEPOOL plan to vote on and file Car-PD almost a year before CAR-SA, they plan on implementing both in time for FCA 19. NEPOOL technical committees expect to vote on CAR-PD in November 2025, and the Participants Committee expects to vote in December 2025.



Source: ISO-NE.