Energy Security Improvements Impact Assessment

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Authors:

Todd Schatzki, Ph.D.
Christopher Llop
Charles Wu
Timothy Spittle
Analysis Group, Inc.

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I. Executive Summary

ISO-NE is proposing new market rules intended to address gaps in the current marketplace that have contributed to concerns about the region's ability to handle on-going and persistent fuel security challenges.[1] Developing long-term solutions to these challenges is important as the challenges may worsen with future changes in system conditions given resource retirements and policy-driven shifts in energy supplies. It is also important that long-term solutions be effective under a range of market conditions, given uncertainty in the direction of these infrastructure changes.

This proposal – the Energy Security Improvements, or ESI – would introduce new day-ahead ancillary services to the market to address identified gaps in energy supplies that can improve reliability outcomes but are not currently incented by the market. By creating these services, the proposal aims to provide technology neutral market signals aligned with the underlying gap in ancillary services needed to address fuel security concerns. In so doing, the proposal aims to improve both reliability and market efficiency, by better aligning individual market participant incentives with these needs.

This report provides an assessment of the impact of these proposed rules, providing both quantitative and qualitative information about how the ESI proposal would affect economic and reliability outcomes as compared to current market rules. Quantitative analysis is based on simulation of the New England day-ahead and real-time energy markets. Using these simulations, impacts are calculated as the difference in market outcomes with and without the ESI market rules changes in effect.

The results of our quantitative analysis quantity the ESI proposal's expected impacts, while also demonstrating how it would be expected to improve incentives for energy security and improved reliability.

First, ESI would create incentives for resources to maintain more secure energy supplies (e.g., higher levels of energy inventories) and generally improve their ability to deliver energy supplies in real-time. These incentives are created through two channels. First, payments to resources supplying DA energy increase as resources are compensated with FER payments for helping to meet the Forecast Energy Requirement. Second, the new ESI products compensate resources that can deliver energy supply in real-time even if these resources are not awarded a DA energy position. These incentives affect all decisions that affect delivery of real-time energy supplies, not only the decisions about fuel supplies that are quantified in our analysis.

Consistent with its market-based design, the analysis demonstrates that these incremental incentives are largest when the system is in greatest need. Moreover, the analysis shows that these incentives are large in magnitude relative to the costs of certain incremental actions (e.g., incremental fuel storage) and are strongest

[1] The authors would like to thank the following Analysis Group, Inc. employees for their assistance with modeling and research as part of this project: Kathryn Barnitt, Tyler Farrell, Leigh Franke, Henry Lane, Danny Nightingale, and Abiy Teshome.

for those resources best able to improve reliability through cost-effective improvements in their ability to supply energy in real-time.

Second, ESI would provide another market through which resources can be compensated for providing energy security and shift the way resources participate in the DA markets to enhance energy security by preserving energy inventory. With ESI, resources with energy inventories can be compensated for maintaining reserve energy supplies via their sale of DA energy options 'backed' by this energy

Third, under ESI, the day-ahead market would be more likely to clear energy supplies equal to (or greater than) forecasted load and any remaining gap between cleared supplies and forecast load will tend to be smaller with ESI. This outcome is a consequence of the auction clearing mechanism under ESI, which will implicitly assign a 'cost' to not meeting the FER.

Fourth, ESI can improve efficiency and lower production costs under stressed market conditions when the increase in energy inventory can reduce energy production from less efficient suppliers and higher cost fuels. Under stressed conditions, production costs are conservatively estimated to fall by $19 and $36 million. These reductions in production costs are separate from the improvements in reliability that ESI would also be expected to create.

Fifth, ESI improves reliability outcomes by increasing incentives to ensure deliverability of energy supplies in real-time. ESI creates incentives by requiring that market participants that sell DA energy options and cannot deliver in real-time pay back their replacement costs during stressed system conditions. Although our quantitative analysis is not designed to analyze system reliability, it quantifies certain aspects of fuel system operations to demonstrate ways in which ESI can reduce stress on fuel systems. The analysis shows that incremental inventoried energy incented by ESI would reduce use of the natural gas pipeline system during tight market conditions, increase aggregate fuel oil inventories, and reduce the rate at which fuel supplies are depleted under stressed conditions.

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While generating these potential benefits, the ESI proposal is also expected to have consequences for payments by load and net revenue to resource owners in the ISO-NE energy markets. **Table 1** provides the estimated changes in total payments for each Central Case.

Table 1. Summary of Impacts to Total Payments

Product / Payment		**Payment**	**Percentage**	**Payment**	**Percentage**	**Payment**	**Percentage**
Change in Energy and RT Operating Reserves	[A]	-$183	-4.5%	-$214	-7.8%	-$41	-2.4%
Net DA Ancillary Services	[B]	$66		$32		$15	
FER Payments	[C]	$250		$113		$61	
Total Payments	[A+B+C]	$132	3.2%	-$69	-2.5%	$35	2.0%

With ESI, aggregate payments by load (to suppliers) would be expected to increase during periods when stressed market conditions are uncommon or infrequent. In the winter months, the estimated change in payments is $35 million over the 3-month winter, while in the non-winter months, the estimated changes in payments is $89 or $125 million (depending on the severity of non-winter market conditions).

Under stressed market conditions, total payments by load (to suppliers) could increase or decrease. The impact on payments under stressed conditions depends on a combination of factors, including the nature of the stressed conditions (e.g., frequency and duration of stressed conditions) and the amount of incremental energy inventory incented by ESI, as this inventory can lower market prices, particularly during stressed market conditions.

Impacts on net supplier revenues vary across resource types, although direction of these impacts under particular market conditions (i.e., whether net revenues increase or decrease) is generally the same across different resource types.

Estimated changes in payments (and generator net revenues) reflect only changes in energy and ancillary services market outcomes, and does not account for changes in payments (and net revenues) from changes in FCM or FRM revenues that potentially occur, for example, due to changes in the net cost of net entry or changes in the FRM design.

II. Introduction

ISO New England (ISO-NE) is proposing new market rules intended to address a number of gaps in the current marketplace that have contributed to on-going concerns about the region's ability to handle persistent concerns about fuel security, particularly as the region's fuel and electricity infrastructure evolves in response to policy and market forces. This proposal – the Energy Security Improvements, or ESI – would introduce new day-ahead ancillary services to the market to address these gaps. The proposal develops day-ahead ancillary service products to address identified gaps in energy supplies that can improve reliability outcomes but are not currently incented by the market. By creating these services, the proposal also aims to improve efficiency by aligning individual market participant incentives with these needs.

This report provides an assessment of the impact of these proposed rules. It provides both quantitative and qualitative information about how the ESI proposal would affect economic and reliability outcomes as compared to current market rules. This information has been developed through a consultative process, with input from both ISO-NE and New England Power Pool (NEPOOL) stakeholders. Preliminary results were shared with NEPOOL stakeholders in a series of presentations that provided preliminary information on the research approaches, data and assumptions we intended to use. Through this process, we received feedback from stakeholders on these approaches, data and assumptions, and incorporated this information into our assessment, when appropriate. We also received requests for quantitative analysis of impacts under particular assumptions that were considered when developing the set of Scenarios that we analyze in our scenario analysis.[2] Our final set of Scenarios addressed a large fraction of these requests and reflected subsequent communications with stakeholders about which requests were the highest priority among scenarios identified in written requests.

A. Assignment

Analysis Group has been asked to develop an Impact Assessment for the ESI market rule changes being proposed by ISO-NE. Our Impact Assessment is designed to provide both quantitative and qualitative assessment of the likely impacts of the ESI proposal to provide stakeholders with information about possible *impacts* of the proposed rule changes (relative to current rules), including the potential efficiency and reliability benefits, costs, impact on consumer payments, and other changes relevant to policy goals. In particular, our Impact Assessment provides information on changes to customer payments and production costs; changes to incentives to market participants to take steps to improve their ability to supply energy in real-time; changes to fuel system operational outcomes that have implications for system reliability; and other expected energy market impacts.

[2] "Energy Security Improvements (ESI) Impact Assessment - Extension Priorities." NESCOE. October 15, 2019. "Scenario Request for Impact Assessment for Long-Term Energy Inventory Security Proposal." Massachusetts Attorney General's Office. August 6, 2019.

Our assessment considers impacts associated with the introduction of new ancillary services into the day-ahead market, but does not consider other elements contemplated at earlier stages of the project but not currently part of ISO-NE's proposed market rule changes, notably a seasonal forward market and a multi-day ahead market. Our assessment reflects the current ISO-NE proposal and provides information on certain design details relevant to this proposal.

Our assessment includes quantitative analysis of the impacts of the ESI proposal on energy market outcomes based on market simulations. This work will both evaluate particular deterministic winter scenarios (not evaluate expected outcomes across a wide range of probability-weighted scenarios), and illustrate particular mechanisms by which ESI may change market outcomes, drawing on particular examples from the model runs. Our assessment does not consider impacts to other New England markets, including the Forward Capacity Market and Forward Reserve Market.

B. Overview of Energy Security Improvements

ISO-NE is proposing the ESI market rule changes to address persistent fuel security concerns within the New England region that create adverse risks to reliable system operations, as well as to address other gaps in the region's current day-ahead markets. Developing robust long-term solutions is important as these challenges may worsen with future changes in system conditions given resource retirements and policy-driven shifts in energy supplies. These fuel security concerns were a focus of an Order from the Federal Energy Regulatory Commission (FERC), which directed ISO-NE to submit "Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns."[3] The ESI market rule changes are proposed in response to this directive.

The ESI proposal is summarized in ISO-NE's "Energy Security Improvements" discussion paper,[4] and further defined in subsequent presentations to the NEPOOL Markets Committee. ESI is designed to provide a long-term, market-based and technology-neutral solution to existing problems in the region's markets, including persistent fuel and energy security challenges. To this end, the ESI proposal introduces multiple new ancillary services to address different gaps in the current services procured day-ahead and thereby improve reliability outcomes.[5] Through additional payments and the financial risks it creates for market participants providing the new ancillary services, ESI creates new incentives for resource owners to deliver energy supply in real-time. These new services can also better align resource incentives to maintain fuel security with the benefits these arrangements provide. In particular, the Discussion Paper identifies a "misaligned incentives" problem that occurs when private incentives to take action to improve their ability to provide energy supply in real-time do not align with society's incentives for market participants to undertake such arrangements.

Specifically, ESI proposes to introduce the following three new ancillary services:

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3 ISO New England Inc., 164 FERC ¶ 61,003 at pp. 2, 5 (2018).

4 ISO New England, "Energy Security Improvements," ISO Discussion Paper, Version 1, April 2019.

5 The ESI Discussion Paper also includes forward market and multi-day ahead market components, although the current proposal is limited to the new ancillary services.

- ***Energy Imbalance Reserves (EIR).*** EIR is designed to cover the gap between forecast energy demand and the supply of energy cleared in the day-ahead market. At present, the ISO ensures reliable operations if there is gap between forecast energy demand and the cleared day-ahead energy supply through supplemental reliability commitments. However, this service (ramping capability from committed units or incremental commitments, if needed) is currently uncompensated.
- **Generation Contingency Reserves (GCR).** GCR corresponds to real-time operating reserves. Thus, GCR provides an approach to securing day-ahead operating reserve supplies, to ensure adequate supplies are available in real-time, and to improve market efficiency by ensuring that day-ahead commitments reflect a co-optimized procurement of energy and operating reserves.
- **Replacement Energy Reserves (RER).** The RER is designed to ensure that there are sufficient energy reserves to maintain reliable system operations in the event of an extended resource contingency. In particular, the RER is designed to ensure that real-time operating reserves can be restored after a system contingency.[6]

ESI would also create a **Forecast Energy Requirement (FER)**, analogous to the EIR, that would compensate resources supplying DA energy for their contributions to helping meet the load forecast. Thus, resources supplying DA energy will be paid both the LMP and the FER price, where the FER price equals the prices paid for EIR. Paying resources that provide DA energy with FER payments both compensates them for helping meet this constraint and ensures that they are no worse off for supplying DA energy, rather than EIR, and supporting incentives to offer at the resource's true opportunity costs.

Together, procurement of these new ancillary services seeks to improve the system's ability to respond to unanticipated, real-time stressed system conditions that create adverse reliability risks, to provide price signals to the market that incentivize market participants to take steps to improve fuel security and resource performance.[7]

The new ancillary services would be delivered through provision of "real" energy options. Market participants would submit offers to supply an energy (call) option, specifying the price at which they would accept the energy offer obligation. A standardized, uniform energy option will be procured for all ESI products. The energy option is structured as a call option, with the supplier paying ISO-NE (on behalf of load) the difference between the real-time LMP and a pre-determined strike price, if that difference is greater than zero. That is, the payment – or "closeout cost" – is:

Closeout cost = maximum (0, real-time LMP – strike price).

Ability to supply each product depends on each resource's physical energy capabilities to ensure that the option for energy supply being procured is consistent with the underlying real-time need associated with each product. Thus, ability to supply GCR products reflects the same operational requirements as real-time operating reserves; ability to supply EIR reflects operational requirements consistent with resources very likely

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6 ISO New England, "Energy Security Improvements: Market-based Approaches, Replacement Energy Reserves," January 14-15, 2020. https://www.iso-ne.com/static-assets/documents/2020/01/a5_a_iii_esi_replacement_energy_reserves_rev1.pptx

7 Mark Karl and Peter Brandien, Letter to NEPOOL Markets Committee, December 4, 2019. https://www.iso-ne.com/static-assets/documents/2019/12/a6_c_i_memo_re_how_market_improvements_address_fuel_security.pdf

to be needed during real-time, and ability to supply RER products reflect longer-lead time (90- or 240-minute) operational capabilities.

Under ESI, the ISO will co-optimize the procurement of energy and energy options in the day-ahead market to clear supply offers and demand bids, ensure load balancing, and meet new ESI product constraints. While the proposal introduces new products to the day-ahead market, market-clearing of New England's real-time energy and ancillary services would be unchanged.

III. Approach to Impact Assessment

The Impact Assessment is performed by evaluating individual scenarios under assumed market conditions. These scenarios do not represent forecasts or predictions of future outcomes. Instead, these deterministic scenarios are intended to represent potential market and resource conditions that might reasonably arise in the future, and provide an indicative snapshot of ESI's impacts under these conditions. The scenario analysis also does not provide an indication of expected future outcomes under ESI, as the model does not weight the likelihood that the different scenarios being evaluated, or scenarios not evaluated, are likely to occur.

Our assessment will reflect both *quantitative analysis* of changes in outcomes from our economic model *and qualitative assessment* of factors not captured by our quantitative analysis. Quantitative impacts are estimated through a simulation of the New England day-ahead and real-time energy markets (including real-time reserves). The production cost model used to simulate the market will be run two times, once using assumptions consistent with market-clearing under Current Market Rules (CMR) and a second time using assumptions consistent with market-clearing under the ESI.[8] Quantitative impact estimates are calculated as the difference in outcomes between the CMR case and corresponding ESI case. For example, our estimate of ESI's impact on total customer payments is the total payments under the ESI case minus total payments under the CMR case. Using this approach, we develop estimates of changes in economic outcomes (e.g., prices, production costs, total payments) and changes in system operational outcomes reflective of reliability impacts (e.g., fuel inventory, reserve shortages).

The quantitative analysis considers different Cases reflecting potential future market and system conditions, and different levels of stress on the fuel supply systems. We consider both winter month and non-winter month cases. Much of our quantitative focuses is on ***impacts in winter months***, because winter energy security poses the most pressing challenges to New England. For the winter months, we evaluate three levels of market and system stress:

- ***Frequent Stressed Conditions ("Frequent Case").*** The Frequent Case is based on market conditions from the winter of 2013/2014. This winter experienced multiple, shorter periods with fuel system constraints, driven in large part by multiple, shorter cold-snaps.

[8] Throughout the report, the acronym CMR is used when referring to the specific "case" we analyze, while the phrase "current market rules" is used when referring to the ISO-NE energy market's current market design and rules.

- ***Extended Stressed Conditions ("Extended Case").*** The Extended Case is based on market conditions from the winter of 2017/2018. This winter experienced one extended period with fuel system constraints, which occurred during a long cold-snap at the end of December and early January.

- ***Infrequent Stressed Conditions ("Infrequent Case").*** The Infrequent Case is based on market conditions from the winter 2016/2017. This winter experienced particularly mild temperatures and no periods of stressed conditions. One indicator of the mildness of these conditions was that natural gas prices never exceeded $13 per MMBtu over the entire winter. Thus, this case does not necessarily represent "normal" or "typical" market conditions.

Impacts in non-winter months are evaluated through two Cases, a Severe Case, reflecting more stressed market conditions (e.g., high customer loads), and a Moderate Case, reflecting typical non-winter conditions without periods of more stressed market conditions. These Cases provide information on ESI's economic impacts but do not analyze changes in operational metrics that signal improvements in reliability.

These winter and non-winter Case assume market conditions consistent with a future year, assumed to be the year 2025/26, and a future resource mix that includes current resources in the fleet and announced retirements and fuel (natural gas) availability consistent with current infrastructure and announced retirements (e.g., Distrigas (Exelon) LNG terminal in Everett, Massachusetts). Other assumptions are based on actual market conditions from the historical periods identified above, including loads, certain resource supplies (such as, wind and solar), natural gas prices and availability of natural gas supplies to the electricity sector (given demand from natural gas Local Distribution Companies (LDCs)).

Our core analysis – or Central Case – evaluates each of these different market conditions (or levels of system stress) in substantial detail. In addition, we analyze multiple Scenarios that alter particular assumptions related to ESI market design, system resources, fuel supplies and costs.

The Central Case is not intended to be "business as usual" cases, but plausible future *scenarios* consistent with the current mix of resources and infrastructure in New England. Consistent with this scenario-based approach to our analysis, we do not assign probabilities to each Case, particularly as these Cases represent a subset of the range of possible future market conditions. It is beyond the scope of this analysis to attempt to assign probabilities to these Cases. While there is substantial weather data available that might support the assignment of probabilities to particular weather conditions, ESI impacts reflect not only factors driven by weather conditions, such as electricity market loads and natural gas supplies, but many factors, such as the retirement and entry of energy infrastructure, that will depend on market, regulatory and policy outcomes that are difficult to forecast.

A. Production Cost Model: Overview

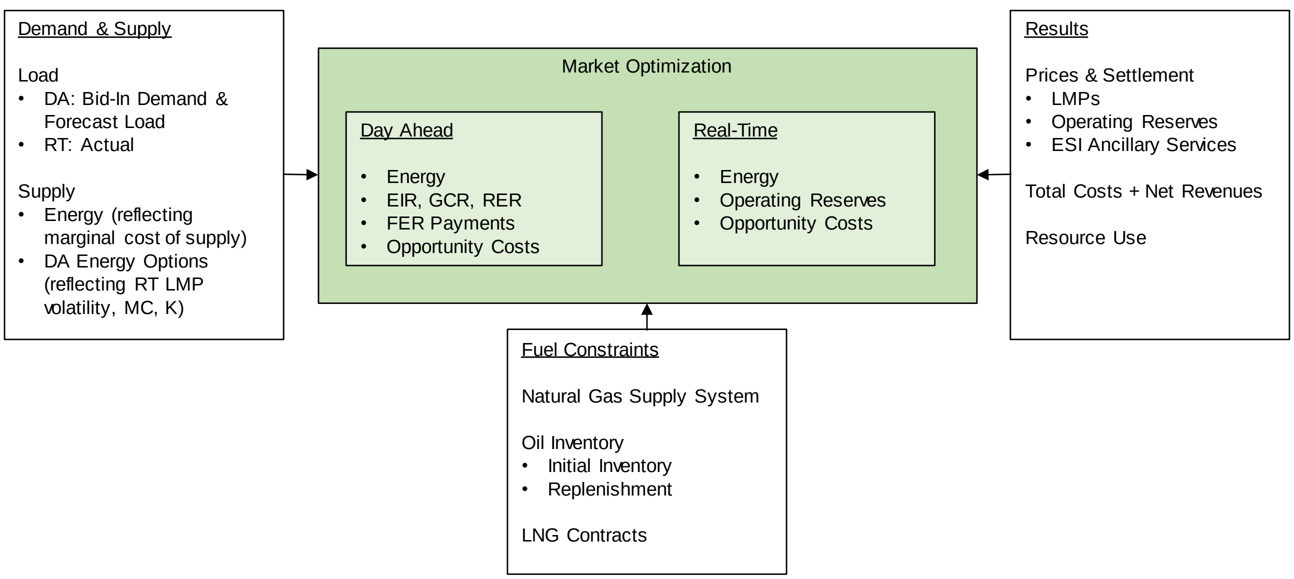
The New England energy market was analyzed using an integrated production cost model that captures key features of the markets needed to reliably measure the impacts of the proposed ESI rules. This model incorporates both day-ahead (DA) and real-time (RT) energy markets, ancillary service (AS) markets for 10- and 30-minute operating reserve (TMR and TMOR, respectively), opportunity cost (OC) bidding options allowing market participants to account for energy limitations for certain fossil resources, and the proposed ESI DA ancillary services, including the Energy Imbalance Reserves (EIR).

The production cost model simulates efficient market clearing consistent with a competitive wholesale energy market. The model maximizes social-welfare as reflected in demand bids and supply offers, while satisfying other physical system requirements, including supply-load balancing, and procurement of various ancillary services in day-ahead and in real-time.

The model simulates market-clearing in each day sequentially, with the outcomes of real-time market clearing in each day affecting the supply offers in subsequent days, given limited fuel supplies and the constraints associated with fuel replenishment. Day-ahead and real-time market-clearing is coordinated, in the sense that the consequences of supply decisions in real-time affect day-ahead offers in a manner consistent with market participants' reasonable expectations about inventories when submitting day-ahead offers.

Figure 1 provides a schematic for the model's structure. Information on supply and demand are input to the model based on each Case's assumptions. In addition, information about fuel constraints is provided to the model, including natural gas supply available to the electricity sector, fuel oil inventories, and forward LNG contracts, if any. These fuel constraints are dynamically determined through the modeling of fuel inventory, including replenishment. The model provides outputs, to be used for analysis, including metrics such as prices (LMPs, ancillary service prices), day-ahead and real-time supply of energy and ancillary services, and fuel inventories.

Figure 1. Overview of Modeling Approach: Model Components



B. Day-Ahead and Real-Time Markets

Within the day-ahead market module, market participants submit supply offers for both energy and ESI products and demand bids to purchase quantities of energy, at different market prices. The model clears these offers to supply and bids to buy such that welfare is maximized, supply equals demand, and ESI ancillary service constraints are met over all hours of the day.[9] Offer prices and quantities for each resource are dynamically bid into the model based on case and resource-specific assumptions (e.g., fuel prices, variable operating costs) and the results of prior days (e.g., accounting for fuel inventory). Bid prices for load reflect the quantity of energy that the market (including physical load and virtual load) is willing to purchase at different prices.

The real-time market module is designed similarly, with three key differences. First, this module includes real-time operating reserves instead of ESI products, consistent with the current market design and the design that would continue under ESI. Second, all offers in the real-time market reflect actual fuel inventory available given previous days' generation and refueling, rather than assuming fuel inventory based on the resource's day-ahead awards. Third, electricity demand is inelastic.

The model evaluates outcomes in winter months and non-winter months. In general, model operations, assumptions and data are similar for winter and non-winter months, but we identify differences when they arise in the descriptions below.

1. Day-Ahead Energy Market Demand

We analyze three future winter cases for the year 2025/26, reflecting Frequent, Extended, and Infrequent stressed conditions. These Cases are based on weather and load patterns from the three-month (December - February) winters of 2016/17, 2017/18, and 2013/14, respectively. We also model two future Non-Winter cases, Moderate and Severe, based on weather and load patterns from the nine-month non-winter period (March - November) for 2017 and 2018, respectively. In each Case, weather patterns and other factors affect both electricity demand and natural gas supply available to the electricity sector, given LDC (non-electricity) demand. Gas supply is discussed in Section III.C.1.

Bids to buy DA energy are based on historical bid-in demand from physical load, virtual trades, and pumped storage. Bid-in demand is modeled as a sloped demand curve (with discreet quantities at unique price levels) in each hour, so the market clears a quantity of supply that maximizes welfare (reflecting bid-in demand) net of the costs of supply and the costs of meeting the various ancillary service constraints. The day-ahead load forecast and real-time load (demand) are based on historical data from the respective year for each Case. These data provide the hour-to-hour patterns that are used in the future cases.

To calculate future (2025/26) values of hourly energy load, we scale the historical values so that future loads are consistent with the forecast peak load and forecast adjusted total energy from the 2019 CELT report for the year 2025/26. For each Case, **Table 2** lists the historical base year used as the basis for hour-to-hour load patterns, and the forecast peak load and adjusted total energy values (from CELT) used as the benchmarks for future loads.

[9] As we describe below, the model includes shortage prices for all DA and RT AS consistent current market rules or the ISO-NE ESI proposal.

Table 2. Summary of Load by Future Winter Case

Season	Case	Base Year	CELT Scenario	Peak Load	Total Energy
Winter	Infrequent Case	2016/17	20/80 Peak Load Unmodified total energy for 2025/26	19,250 MW	31,525 GWh
	Extended Case	2017/18	50/50 Peak Load Predicted total energy for 2025/26 +1%	19,436 MW	31,840 GWh
	Frequent Case	2013/14	80/20 Peak Load Predicted total energy for 2025/26 +2%	19,837 MW	31,156 GWh
Non-Winter	Moderate Case	2017	50/50 Peak Load Unmodified total energy for 2026	24,315 MW	88,287 GWh
	Severe Case	2018	80/20 Peak Load Predicted total energy for 2026 +1%	25,412 MW	90,053 GWh

Day-ahead bid-in demand varies between the CMR and ESI cases. In the CMR cases, bid-in demand is based on historical bid-in demand, calibrated so that the market clears at a price (LMP) consistent with historical day-ahead energy market outcomes (that in principle are consistent with expected real-time market outcomes), while still accounting for changes in demand from historical to anticipated future levels. In the ESI cases, bid-in demand also accounts for the shift in demand that would occur due to the impact of ESI on LMPs and the market response given arbitrage opportunities. We discuss this further in the next section.

2. Day-Ahead Ancillary Service Products

The model simulation clears supplies of day-ahead energy options to meet the new ESI constraints. This simulation co-optimizes the market-clearing of all products in the day-ahead market, including energy and each of four ESI products – GCR10, GCR30, RER, and EIR.[10]

We model hourly requirements for GCR10, GCR30, RER, and EIR. For GCR, we model GCR10 and GCR30, but do not account for separate spinning and non-spinning requirements for GCR10. The model assumes the required quantities of GCR10 and GCR30 are 1,600 and 2,400 MW, respectively, levels that are consistent with the ESI proposal. While, in practice, these values will vary from day to day depending on each day's first- and second-contingencies and load forecast error, we expect this variation is sufficiently small that assuming a fixed requirement is unlikely to meaningfully affect estimated impacts. Committed GCR10 quantities cascade, such that they can cover both the GCR10 and GCR30 requirements.

For RER, we model a single RER product, combining the RER90 and RER240 products. The model assumes a fixed requirement of 1,200 in each hour for both RER90 and RER240. This requirement cascades with the GCR10 and GCR30 requirements, such that the combined requirement of GCR10, GCR30, and RER is 3,600 MW.

The EIR requirements is modeled endogenously as a function of cleared energy supply – which is solved simultaneously – and the ISO-NE load forecast, which is fixed in each hour. We describe this constraint in further detail below, in Section III.B.5.

[10] The model solves for one RER product, as opposed to the two products currently proposed by ISO-NE.

ESI product rewards are limited by resource-specific characteristics given each resource's ability to provide each ESI service. Offline capability reflects a unit's Claim10, Claim30, "Claim60", or "Claim240" capability for GCR10, GCR30, EIR, and RER, respectively.[11] A unit with a DA energy award can also supply ESI products through the unit's ramp capability, and the model's logic is designed such that this ramp capability can receive an ESI award only when it is also supplying DA energy (in quantities consistent with a plant's minimum load).[12] Data on Claim10, Claim30, "Claim60", and "Claim240" capability are provided by ISO-NE.

The analysis also assumes ESI awards are limited by the availability of fuel to physically support the DA energy option. At the resource level, cleared DA energy option quantities are limited to the resource's available energy inventory. For example, oil-only units must have fuel in inventory to cover an ESI product award. At the system level, the total supply of ESI products awarded to gas-only resources is limited by the hourly supply of natural gas available through the pipeline system to the electricity sector.

Prices for each ESI products are limited by administratively determined penalty factors. Penalty factors cap the price for each ESI product, includes circumstances when there is insufficient supply of eligible DA energy options to meet a particular requirement. **Table 3** provides the modeled penalty factors (per MWh), which align with ISO-NE's proposed market design:

Table 3. Day-Ahead Ancillary Service Penalty Factors

Ancillary Service Product	Penalty Factor (per MWh)
RER	$100
GCR30	$1,000
GCR10	$1,500
EIR	$2,929

3. Day-Ahead Energy Market Supply

Our analysis assumes resources currently in the New England market, defined to be resources that have cleared the 13th Forward Capacity Auction (FCA 13) but have not submitted retirement notifications for FCA 14. This assumes the retirement of the Mystic 8 and 9 generation facility that currently has a reliability must run contract. **Table 4** summarizes the mix of resources by resource-type, reporting total capacity by category for the winter months, based on winter claimed capability. The non-winter month analysis relies on summer claimed capability. The fleet of resources are the same under CMR and ESI, although certain gas-only resources are categorized differently – under ESI these resources have a forward LNG contract, whereas under CMR they do not.

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11 Claim10 and Claim30 are currently defined parameters, and Claim60 and Claim240 are the analogous parameters for 60- and 240-minute capability to deliver energy within 60 and 240 minutes, respectively.

12 For simplicity, resources are modeled as either "claim" (cold start) or "ramp" (must be providing energy) eligible.

Table 4. Future Resource Mix Scenarios, Winter Months, Nameplate Capacity (MW)[13]

	CMR	ESI
Natural Gas Fired Resources		
Natural Gas with Oil Dual Fuel	8,320	8,320
Natural Gas Only	8,582	7,989
Natural Gas with LNG Forward Contract	0	593
Natural Gas Fuel Cell	27	27
Oil Only	6,601	6,601
Coal	549	549
Nuclear	3,472	3,472
Hydroelectric Resources		
Hydro: Pondage	1,241	1,241
Hydro: Run-of-River	749	749
Pumped Storage	1,778	1,778
Wind Resource		
Land Based Wind	1,401	1,401
Offshore Wind	832	832
Solar	1,671	1,671
Biomass/Refuse	830	830
Battery Storage	458	458
Price Responsive DR	267	267
Total	**36,778**	**36,778**

Energy-supplying resources are modeled as either **optimized resources** or **profiled resources**.

Optimized resources offer their available capacity into the market in each hour at a price reflecting their marginal cost of production. These resources include fossil fuel resources, nuclear, biomass, fuel cells, price responsive demand, and imports.[14] Resource offers are generally the same for winter and non-winter months, with the exception of available capacity, which varies by season.

For each resource, the total day-ahead supply each resource can clear in the market – including DA energy and ESI products – is limited to its FOR-adjusted seasonal claimed capability. Market-clearing reflects resource-specific offers for supplying a DA energy option.

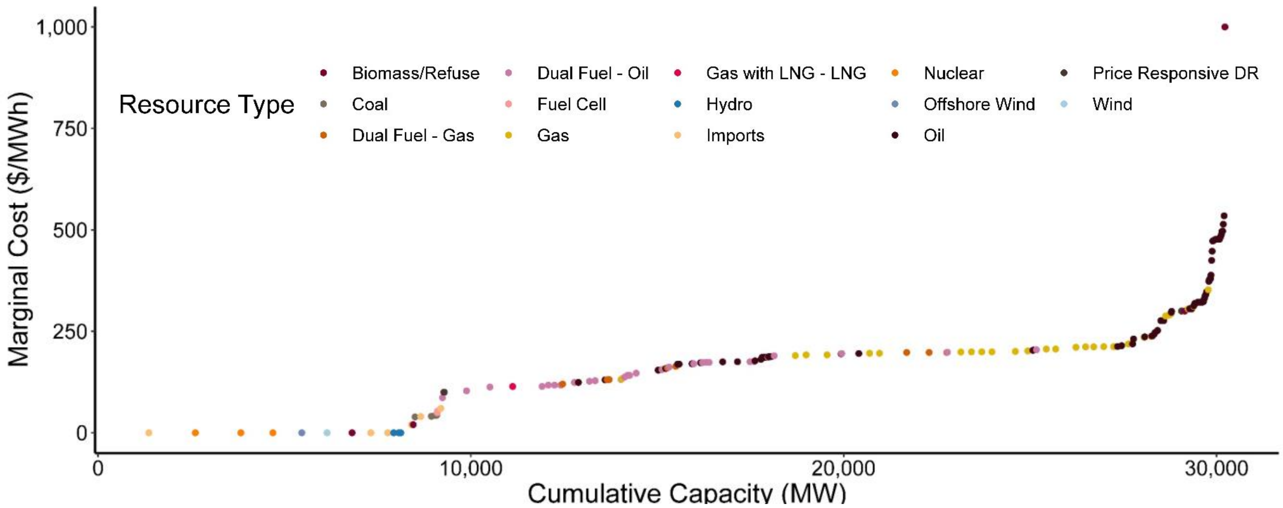
Supply offers from optimized resources are used to create a supply curve, as illustrated in **Figure 2**. In each hour, resources offer into the energy market their maximum capacity (EcoMax) adjusted for its average forced outage rate (FOR). As we describe in further detail below, supply from some resources may be limited by fuel inventories and the capacity of fuel systems. These limits include resource-level constraints due to limited fuel

[13] Capacity based on FCA 13 results (excluding resources that have submitted FCA 14 retirement notifications) and winter claimed capability from the 2019 CELT Report. In addition to these FCA-cleared units, future supply includes 886 MW of new solar capability, 458 MW of battery storage, and 1,339 MW of wind capability (507 MW onshore, 832 MW offshore. The non-winter month analysis assumes summer claimed capability. Additional information on assumed retirements is provided in the appendix.

[14] The full set of dispatched resources are: Gas, Oil, Coal, Nuclear, Biomass/Refuse, Imports, Fuel Cell, and Price Responsive D.R.

oil inventories and limited LNG contracts, and system-level constrains due to fixed natural gas pipeline transmission infrastructure.[15]

Figure 2. Illustrative Resource Supply Curve



Each resource's supply is offered at a price based on its marginal cost of supplying energy. The marginal cost of supply can reflect production costs and opportunity costs. Marginal production costs for fossil resources include costs for fuel, variable operations and maintenance (O&M), and emission. These costs reflect resource-specific characteristics, including fuel type, heat rate, and emission rates.[16] Dual-fuel (gas/oil) resources are modeled such that unit offers supply using the fuel with the lowest marginal cost, subject to constraints on fuel supply.

Unit-specific production costs, heat rates, and emissions rates underlying units' offers are based on data from SNL Financial as of August 2019. Units not yet in service are assigned unit characteristics from similar, recently-built units. Reserve and DA energy option capabilities (Claim10, Claim30, "Claim60", "Claim240") for each unit are provided by ISO-NE.[17]

The model simplifies unit offers by assuming supply is offered in one block rather than multiple blocks. This assumption simplifies certain modeling complexities that are beyond the project's scope, but should not meaningfully affect the analysis of ESI's impacts. The model accounts for certain unit operational limitations.

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15 Day-Ahead fuel inventory limits are calculated by assuming that the previous day's DA market result (i.e. for the current day) will match the current day RT market and therefore represent the exact expected fuel inventory for the end of day into the subsequent day.

16 For additional information on data sources, please see [Section III.B]. Emission costs for Massachusetts Global Warming Solutions Act compliance are $5.27 per metric ton based on the CO_2 emissions price for each fuel type is the clearing price from the Regional Greenhouse Gas Initiative of New England and Mid-Atlantic States of the US (RGGI) 43rd auction held on March 13, 2019.

17 Claim10, Claim30, Claim60, and Claim 240 represent the capacity in MW that a unit can provide from an offline state in 10, 30, 60, and 240 minutes, respectively.

Units that can supply DA energy options or real-time operating reserves through ramp capability can only provide such ancillary service supply when also supplying energy.

For resources with limited fuel inventory, particularly oil-fired resources, offers reflect both the resource's production costs and its opportunity costs. Because of these resources' limited fuel inventory, supplying energy in one hour may limit a resource's ability to supply energy in a different hour, in the same day or in a subsequent day. **Opportunity cost adders** allow a resource to account for this opportunity cost, and increase the likelihood that limited energy supply is used in highest value hours. Market rules were recently enhanced to allow resources to include these opportunity costs in their offers.[18]

In our analysis, opportunity cost bid adders are calculated using a similar methodology to that incorporated into the opportunity cost models that ISO-NE makes available for market participant use. The adder reflects expected net revenue earned by a resource's "last" unit of energy over a three-day, multi-day horizon when hourly net revenues are sorted from highest to lowest. The net revenues of a resource's last unit of energy is calculated assuming the resource only provides energy during the most profitable hours and that the resource has imperfect information about the fuel inventories of other resources and future energy prices. A resource only has an opportunity cost in situations where fuel is limited: if there is enough fuel to operate as expected for all profitable hours in the future time horizon at-issue, the resource has an opportunity cost of zero because it is assumed that using energy now will not preclude it from producing energy in the future.[19]

Imports are categorized as either price-responsive or non-price-responsive based on analysis of historical import offer patterns. Price-responsive imports are modeled using an offer curve calibrated against historical pricing, while non-price-responsive imports are modeled as a fixed quantity of imported energy in every hour.

Profiled resources are assumed to provide supply at levels consistent with historical supply patterns. For these resources, we rely on historical patterns because these resources would otherwise be particularly complex to model (e.g., battery and pumped storage units) or their output based on exogenous factors (e.g., variable renewables).[20] For existing resources, we assume that each resource supplies energy and ancillary services consistent with its historical supply. For new resources (i.e., cleared in a Forward Capacity Market, but not yet operational) with a profiled technology, we assume supply consistent with existing resources in the market. For variable renewable generation, including wind and solar generation, base year generation output is scaled to future levels consistent with new capacity that has cleared the FCA but is not yet operational. For example, given 2017-2018 historical total solar nameplate capacity of 941 MW and assumed future total solar nameplate capacity of 1,671 MW, the solar output for each hour is scaled up by 77.5 percent (1,671 MW/941 MW = 1.775). Offshore wind generation profiles are based on historical wind buoy data from ISO-NE.

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18 Lowell, Jonathan, "Opportunity Costs and Energy Market Offers (Phase 1), ISO's Proposal to Estimate Opportunity Costs for Oil and Dual-Fuel Resources with Inter-temporal Production Limitations," October 9-10, 2018. https://www.iso-ne.com/static-assets/documents/2018/10/a7_presentation_opportunity_costs_and_energy_market_offers.pptx

19 For more information on the opportunity cost adder calculation, see the appendix.

20 The full set of profiled resources are: Battery Storage, Hydro - Pondage, Hydro - Run of River, Hydro - Weekly, Pumped Storage, Solar, Offshore Wind, and Wind.

For profiled resources, we assume that each resource supplies GCR10 and GCR30 at levels consistent with historical supply of 10- and 30-minute real-time operating reserves. If the total quantity of historical cleared operating reserves exceeds the assumed GCR10 and GCR30 requirements (which occurs in some hours), the excess supply is used to offset the RER requirement.

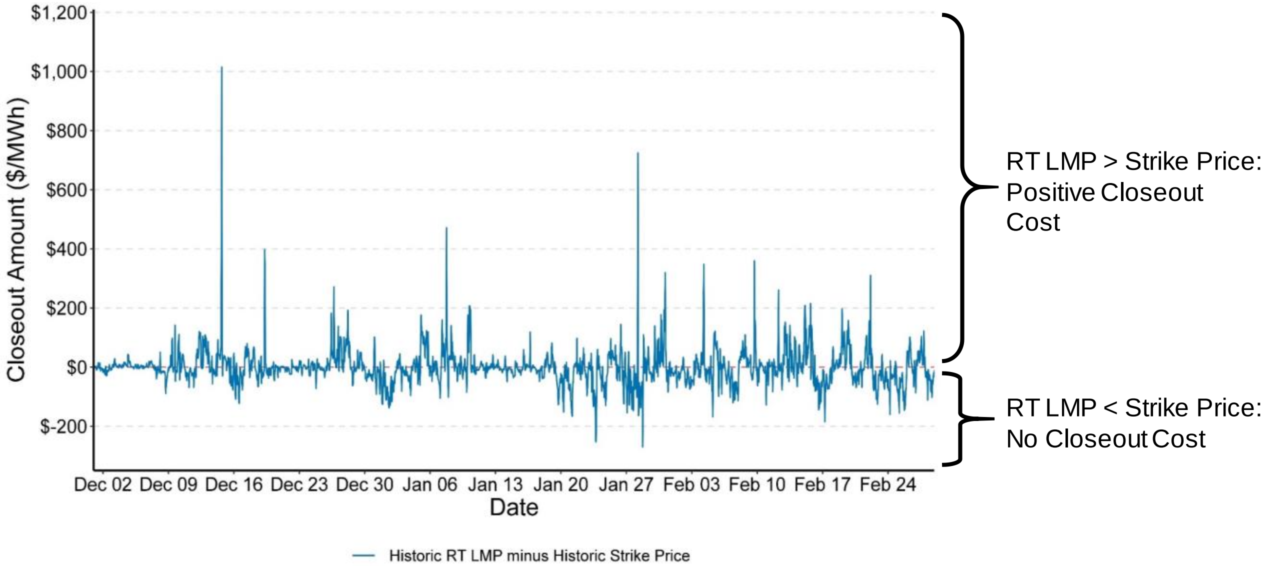
4. Day-Ahead Energy Option Offers

Under the ESI proposal, market participants submit offers to supply energy options into the DA market. While the ESI proposal includes multiple products, the same underlying commodity – a DA energy option with the same strike price and settles against the same RT LMP – is used to satisfy each of these new ESI requirements. Thus, each resource submits offer(s) for one commodity – the DA energy option – in each hour, even though the market participant may be able to supply different ESI products, depending on the unit's characteristics.

While the same energy option is procured for each service, market-clearing prices for ESI products can differ if higher cost resources are needed to satisfy the requirements for products with more-restrictive eligibility requirements. For example, the GCR10 price may be greater than the prices for other ESI products if resources meeting the more restrictive 10-minute operational requirement offer options at a higher price. But, a more flexible resource, able to provide multiple ESI products, is compensated for the "highest quality" product it can provide.

The seller of a DA energy option faces a basic tradeoff: in exchange for an upfront payment (the option "price"), the seller agrees to pay the holder the difference between the RT LMP and the strike price, if this difference is positive. Given uncertain RT LMPs, the seller receives a sure payment in exchange for uncertain (potentially zero) closeout cost. This risky closeout cost is illustrated by **Figure 3**, which shows the difference between the RT LMP and the strike price on each day, where the strike price is set to the hourly historical day-ahead LMP. Our analysis estimates the amount a market participant would need to be paid in the form of an up-front payment in the Day Ahead Market (its willingness to accept) for taking on this closeout cost risk.

Figure 3. DA Energy Option Closeout Cost, RT LMP – Strike Price, Winter 2013/14



Note: Strike Price is modeled as the historical DA LMP.

We estimate supplier offers for DA energy options through a quantitative analysis based on historical market data. The estimates reflect the basic financial tradeoff for suppliers if they are awarded a DA energy option. If they are awarded an option, they receive a fixed payment, reflecting the market-clearing price for the ESI product. In return, they agree to pay a settlement (or "closeout") cost, which is a function of the difference between the RT LMP in that hour and a strike price, which is fixed prior to selling the option. When RT LMPs are higher than the strike price, the option is "in the money" and suppliers must pay the difference between the real time LMP and the strike price. When this difference is zero or negative, the option is "out of the money" and the closeout cost is zero. Regardless of the closeout cost, option suppliers keep the fixed payment earned by writing the option.

Competitive offers for DA energy options will reflect their willingness to accept the obligation to settle ("closeout") at the option's payout terms (to ISO-NE). In principle, this valuation reflects many factors, such as the expected payout, the risk associated with the option, and the resulting financial risk faced by market participants, given a potential correlation between option settlement and other revenue streams.

To estimate offer prices for DA energy options, we assume that suppliers' willingness to accept reflects expected closeout costs plus a premium to capture the financial risk associated with the uncertain closeout costs. That is, in each hour:

$$DA\ energy\ option\ offer(h)\ = expected\ closeout\ cost(h) + risk\ premium\ (h)$$

This approach differs from the approach commonly taken to estimate the value of options traded in financial markets, which relies on constructing a portfolio (a "replicating portfolio") of financial product that replicates the returns for the derivative. The options procured through ESI, however, cannot be replicated through a portfolio of thickly traded assets (e.g., forwards and cash positions), as is the case for many financial derivatives.[21] Thus, valuations will reflect each market participant's expectations regarding likely costs and associated risks, potentially modified by opportunities to hedge such risks through other market products.[22]

Further, our analysis assumes that all market participants submit offers for DA energy options that reflect their underlying valuation, with the resulting market-clearing price reflecting the marginal offers given the quantity administratively procured. The resulting price will differ from the price that emerges from financial markets, where equilibrium prices reflect bi-lateral transactions between those willing to accept and willing to pay for the derivative.

The analysis (as well as the settlement of the DA energy options) is undertaken using historical real-time LMP data. The use of historical data provides a robust approach to valuing DA energy options, as the option value is dependent on the distribution of returns. Among available options, the use of historical data is the most robust approach to estimating this distribution, as other approaches would require parametric assumptions without an empirical foundation. Future market conditions may differ from historical market conditions, but the alternative approaches to estimating expected costs (or option values) do not better address such potential differences compared to relying on historical data. Scenario analysis in which the risk premiums are varied tests the sensitivity of this assumption.

When estimating option offers, the strike price varies by hour and is set at the historical DA LMP in each hour. In practice, of course, the ESI proposal envisions that the strike price will be set through different means, as the DA LMP price will not be known when the DA market is run. But, for the purposes of our analysis, the DA LMP provides a reasonable estimate of the market's expectations for the hourly RT LMPs in each hour, even if it would likely be more precise than any metrics available for use to set the strike price. **Figure 4** and **Figure 5** provides the distribution of all estimated offers and all cleared offers across all hours in the Frequent Case.

21 The real options procured through the ESI proposal differ in many respects from financial options for thickly traded assets, such as stocks traded on major exchanges. The underlying asset for the DA energy options – real-time LMPs – is not traded on any open exchange, making it impossible to "replicate" the option through a combination of cash purchases and forwards. Thus, the risk and financial properties of these options will differ from those on more liquid financial assets.

22 Cochrane and Saa-Requejo, 1999, consider approaches to derivative valuation that reflect "good deals" given opportunities to partially hedge a derivatives risks.

Figure 4. DA Energy Option Offers, All Offers, Frequent Case

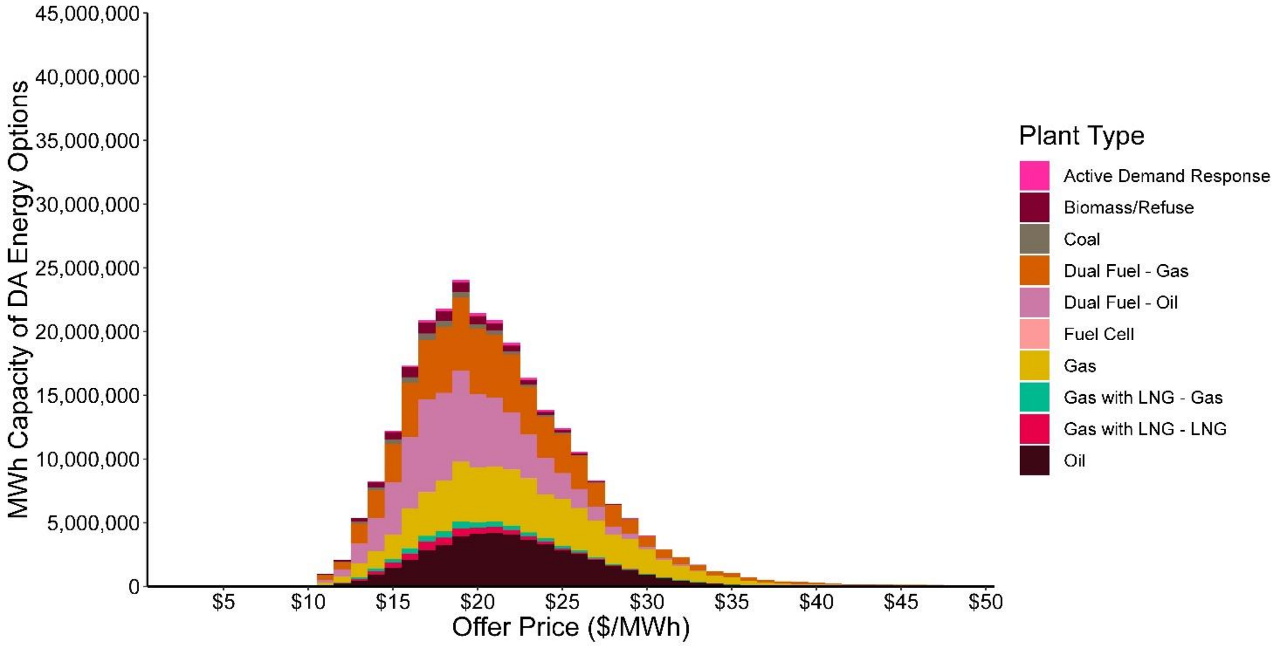
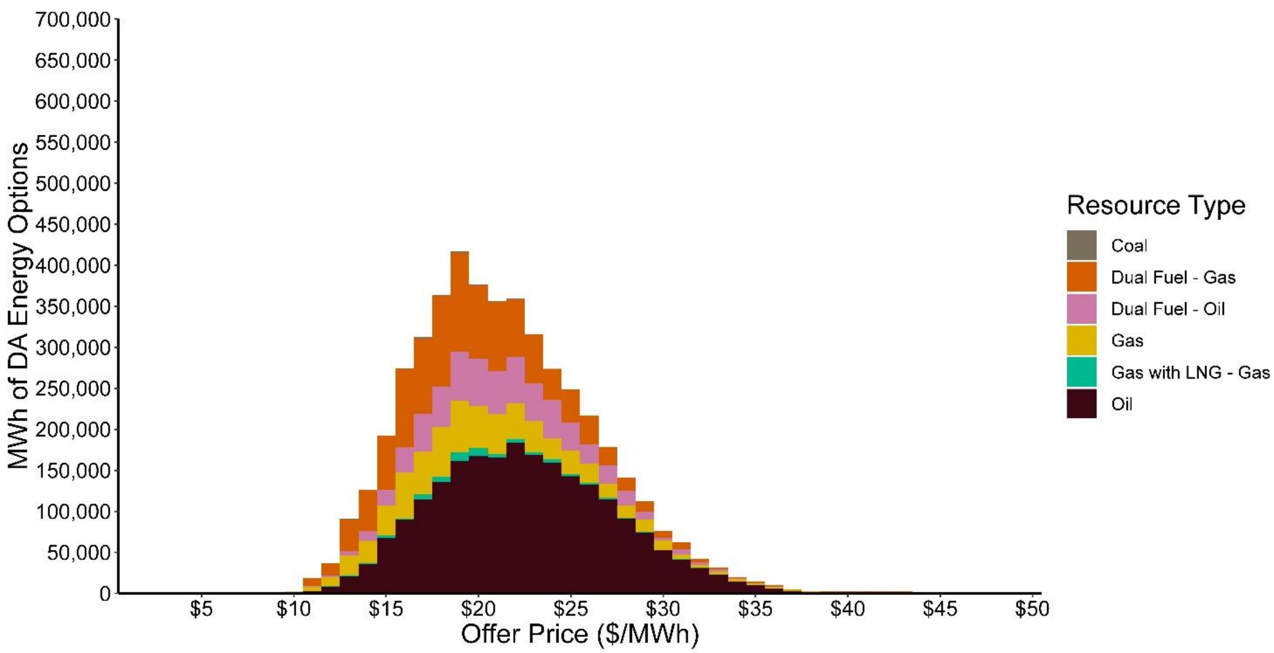


Figure 5. DA Energy Option Offers, Cleared Offers (Marginal and Infra-Marginal), Frequent Case



Below, we briefly describe our methodology for estimating the offer prices for DA energy options. In the appendix, we describe our methodology in greater detail.

a) Expected Closeout Costs

Expected closeout costs are estimated through a simulation process drawing on historical data from recent winters (2012 to 2018). This simulation process is used to estimates the distribution of RT LMPs (relative to the strike price) in each hour, and then estimate the expected closeout cost of the option conditional on that distribution. Because the closeout costs of the DA energy option have an asymmetric structure, with positive costs if the RT LMP exceeds the strike price and no cost otherwise, it is necessary to evaluate this distribution to ensure that the expected cost is not understated.

Expected closeout costs are assumed to be uniform across all market participants. While, in reality, there may be differences in market participants' expectations regarding RT LMPs, the challenges associated with estimating these impacts for each supplier across all potential market conditions would be significant. Thus, all heterogeneity in DA energy option offers is due to the risk premiums, which differ across resources.

Expected closeout costs are estimated in several steps. First, we develop a "point estimate" for the difference between the RT LMP and the strike price (i.e., *RT LMP – K*) given hour-specific market and weather conditions. This point estimate is created by estimating a linear regression model for *RT LMP – K* as a function of several variables, including temperature, rolling historical volatility in closeout costs, and various date fixed effects, and then using this model to estimate a fitted value based on each hours unique conditions.[23] Including these variables in the regression controls for information that would be available to suppliers when forming expectations about closeout costs in order to develop an option offer price in the day ahead market. The second step accounts for the statistical uncertainty in our point estimate, using Monte Carlo simulations to estimate the probability distribution of potential values of the difference between the RT LMP and the strike price (i.e., *RT LMP – K*) in each hour.[24] Having generated a distribution of potential values of *RT LMP – K*, we calculate the closeout cost in each simulated value and then calculate the average closeout cost across all of the simulated values. This approach accounts for the asymmetric nature of the option's closeout costs (which are positive if *RT LMP – K* > 0, but zero otherwise) to more accurately estimate the expected closeout costs.

b) Risk Premium

Our estimates for risk premiums build off risk preferences revealed in the market. In particular, we assume that the risk premiums for taking forward positions in DA energy markets provide information about market participants' willingness (positive or negative) to take on a risky forward position. The estimated risk premium component of the DA energy option offer reflects estimates of these forward risk premiums, with adjustments

[23] The model is fit using data from winter months from December 2012 through February 2019. For the non-winter cases, the same model is fit to data from each of the nine-month periods that comprise the non-winter seasons.

[24] This simulated volatility is achieved by creating a distribution of potential values of (*RT LMP – K*) for each hour, where the values of (*RT LMP – K*) equal the fitted value plus a volatility term sampled from the regression model's residuals (i.e., the difference between the fitted and actual values of (*RT LMP – K*)). This sampling is performed 1,000 times for each hour, to arrive at a set (distribution) of 1,000 potential values of (*RT LMP – K*) for each hour. We then set the closeout cost to zero whenever (*RT LMP – K*) is negative, and then take the mean of all 1,000 values in each hour to arrive at the estimate the expected closeout cost for that hour.

made to account for the relative sizes of forward energy prices to day ahead energy option prices, and the relative (absolute) magnitude of the financial risk, measured by the standard deviation of returns. **Figure 6** and **Figure 7** provide the estimated risk premia for all hourly DA energy offers and cleared DA energy offers for the Frequent Case. Further details on the methodology we used to estimate the risk premiums is provided in the appendix.

Figure 6. All DA Energy Option Risk Premia, Frequent Case

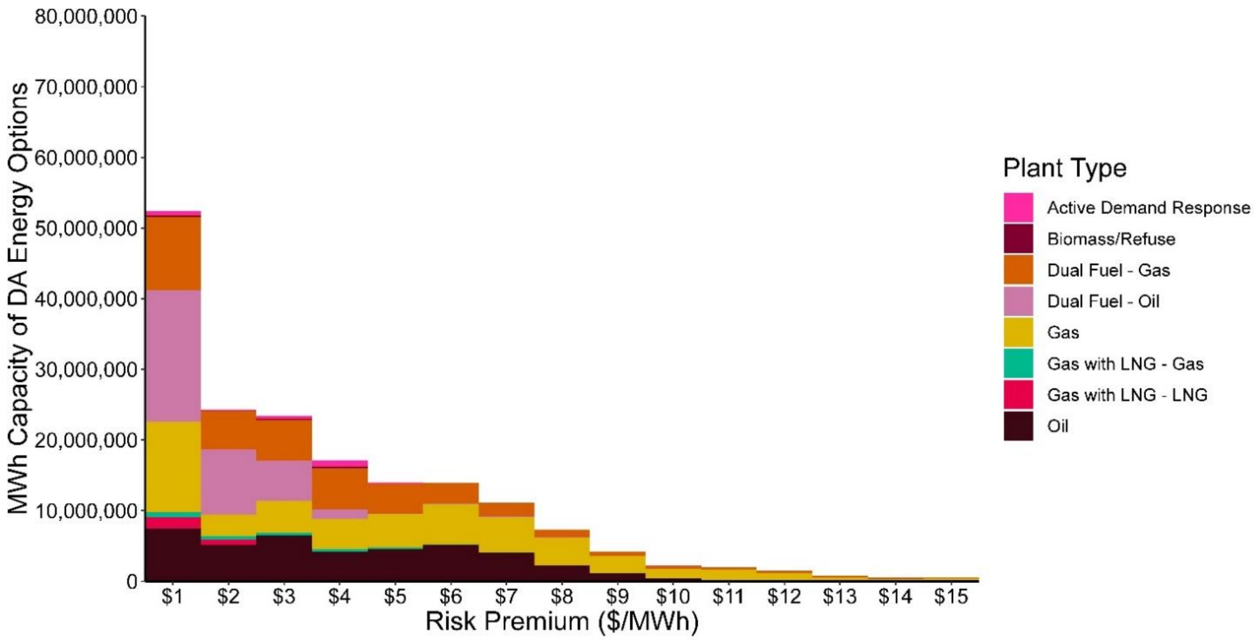
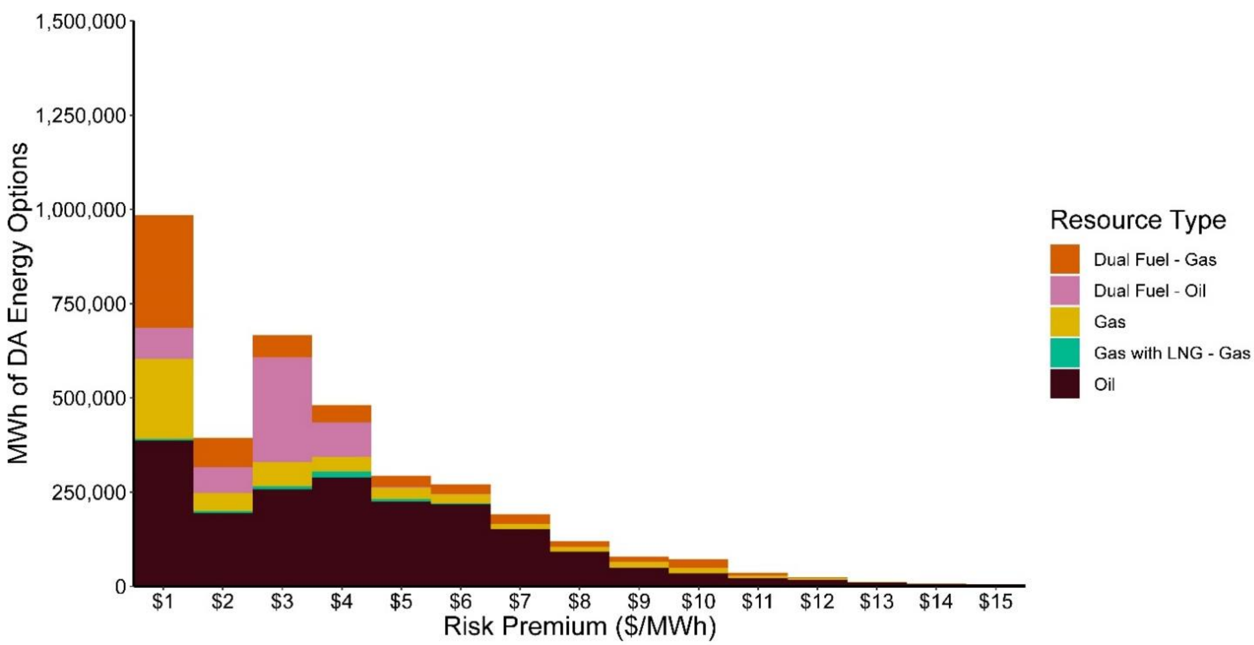


Figure 7. DA Energy Option Risk Premia for Cleared Offers, Frequent Case



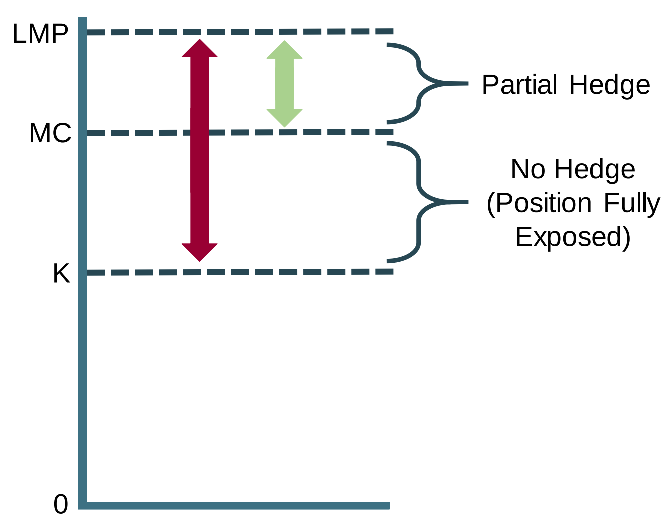
Like any financial option, financial risk is greatest when settlement costs are more volatile. With higher volatility, there is a greater risk of large closeout costs that can have a variety of follow-on corporate implications (e.g., impacts to cash flow or credit ratings). Thus, we assume that the risk premium is greater for higher levels of RT LMP volatility.

Because of this volatile return, a DA energy option affects the financial risk faced by suppliers. However, the impact of a DA energy option award on a supplier's financial risk will depend not only the magnitude of this risk but also on other market net revenues earned by the supplier and the extent to which these revenues are correlated with the DA energy option's closeout costs.

Closeout costs will typically be negatively correlated with supplier revenues in the RT energy markets. When RT LMPs exceed the strike price, set roughly at the corresponding DA LMP for that hour, this is a signal that additional energy is needed above the amount of cleared day-ahead. Thus, some suppliers that did not sell energy day ahead are likely to be receiving incremental RT energy revenues during hours when closeout costs are positive (i.e., RT LMP > strike price). Via this mechanism, the holding of energy inventory hedges the risks associated with the DA energy option.

The hedge provided by physical energy inventory is greatest when this inventory can be supplied to the market at a lower marginal cost. This point is illustrated by **Figure 8**. Assume that the strike price is *K* and DA energy option settles at *LMP*. In this case, the closeout cost faced by someone holding a DA energy option is represented by the red arrow. Suppose, however, that this resource has energy inventory that can be supplied to the market at marginal cost of MC. In this case, the option holder earns *LMP – MC* in net energy revenues, while paying out *LMP – K* in closeout costs, resulting in a smaller net loss of *MC – K* (before accounting for the initial day ahead payment for selling the option). Thus, the physical energy inventory provides a partial hedge to the DA energy option's risks.

Figure 8. Illustration of Physical Hedge Provided by Energy Inventory to DA Energy Option Risk



As the above example illustrates, the extent to which physical energy inventory hedges the risks of a DA energy option depends on the marginal costs at which that inventory can be supplied. When the marginal costs are low, the inventory provides a more effective hedge, whereas when the marginal costs are high, the inventory provides a more limited hedge. As a result, the financial risks of a DA energy option depend on the resource's marginal costs, given the potential for this energy supply to offset closeout costs when RT LMPs are higher. Thus, we account for the resource's cost of energy supply when calculating risk premiums.

The potential for physical energy inventory to mitigate the financial risk of a DA energy option depends not only on the marginal costs of this supply, but also on operational and intertemporal factors that may limit a resource's ability to supply energy in real-time in response to higher-than-expected prices. We account for certain of these operational and intertemporal factors when calculating the risk premium. These factors include:

- ***Performance Risk.*** For all resources, there is the risk that the resource fails to perform when requested due to a forced outage or other operational factors (e.g., transmission outage).
- ***Lead Time and Intertemporal Factors.*** Lead times required for a resource to become fully energized and other intertemporal factors may limit a resource's ability to hedge closeout cost risk through its physical energy inventory. Lead times may limit the ability of some resources to deliver energy supply to cover the real-time settlement cost of a DA energy option. Similarly, some resource's supply may be limited by inter-temporal factors, as reflected by offer parameters such as minimum run-time and minimum down-times.
- ***Fuel Cost Risk.*** Natural gas-only resources face fuel price risk because prices may be higher in the intra-day natural gas markets compared to the day-ahead natural gas market and trading in supply for delivery to a particular resource may be illiquid.
- ***Start-up Cost.*** Offline resources may incur start-up costs in addition to short-run marginal costs for physical energy supply to cover a DA energy option settlement. This factor considers this incremental cost via an additional risk factor.

These parameters vary across technologies, depending on technology-specific attributes. **Table 5** shows how these factors vary across technologies, with more detail provided in the appendix. In the table, a check mark indicates that the category is modeled for the given technology. A check with a "+" symbol indicates that the levels modeled are greater, relative to those with just a check.

Table 5. Operational and Intertemporal Factors Accounted for in Risk Premium

	Operational and Intertemporal Factors (*p*)		Cost Factors (*m*)	
	Performance Risk	Lead Time	Fuel Cost Risk	Start-up Cost
Combustion Turbines				
Gas-only			✓+	✓+
Oil-only, Dual Fuel			✓	✓+
Combined Cycle				
Gas-only	✓	✓	✓	✓
Oil-only, Dual Fuel, LNG Contract	✓	✓		✓
Steam				
Oil-only, Dual Fuel	✓+	✓+		✓

5. *EIR Requirement and FER Payments*

The EIR constraint ensures that there is sufficient energy available to meet forecast energy in each interval. With other ESI products (RER and GCR), the quantity procured is generally independent of the quantity of energy procured. However, with EIR, the market clearing algorithm (endogenously) *solves for both the quantity of EIR and the quantity of cleared DA energy*. Specifically, the EIR constraint has the following structure:

EIR = max(0, forecast load – cleared physical DA energy supply)

By virtue of this structure, so long as DA energy is less than forecast load, additional DA energy supply (backed by physical resources) reduces the quantity of EIR that needs to be procured to ensure that there is energy in real-time to meet the forecast load. For example, assume the cleared physical DA energy is 100 MW and the forecast load is 110 MW, so that the **EIR is 10 MW**. Consider the impact of a 1 MW increase in cleared DA physical energy from 100 MW to 101 MW. With the 1 MW increase in energy, the total cost to procuring DA energy increases. But, the 1 MW increase in DA energy reduces EIR by 1 MW to 9 MW:

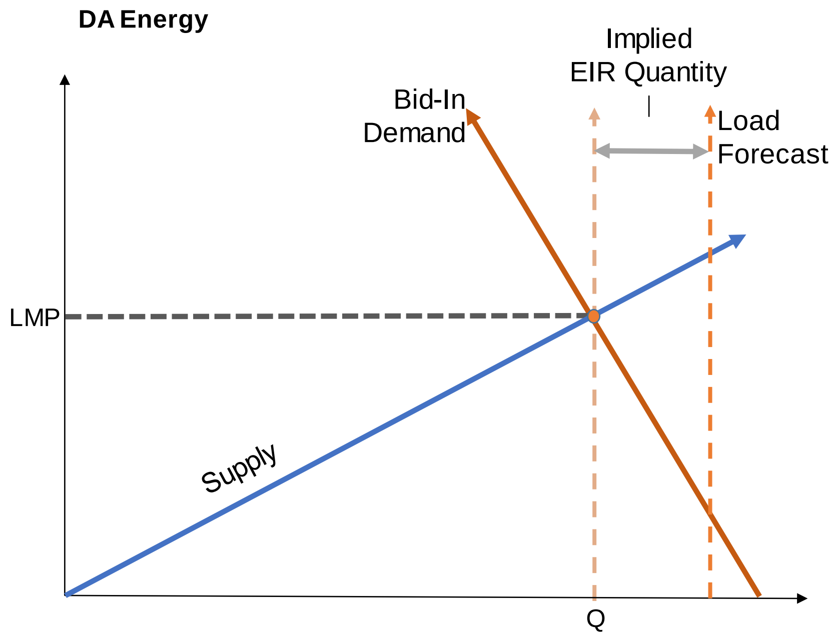
EIR = max(0, 110 MW – (100 MW + 1 MW)) = 9 MW

Thus, if the DA optimization clears 1 MW of additional energy, it will reduce the quantity of EIR by 1 MW, which in turn will lower costs.

When determining the optimal quantity of DA energy and EIR, the optimization accounts for this interaction, which is an inherent element of the ESI design. As a result, when determining the quantity of DA energy that clears the market, the clearing algorithm accounts for both the cost of additional DA energy and the savings in EIR procured.

Under current market rules, the DA energy market generally clears at a price and quantity at which the supply offer curve and bid-in demand curves intersect. As shown in **Figure 9**, the resulting outcomes can lead to a gap between the quantity of physical energy that clears the market and the load forecast. In **Figure 9**, this gap is represented by the "EIR Quantity".

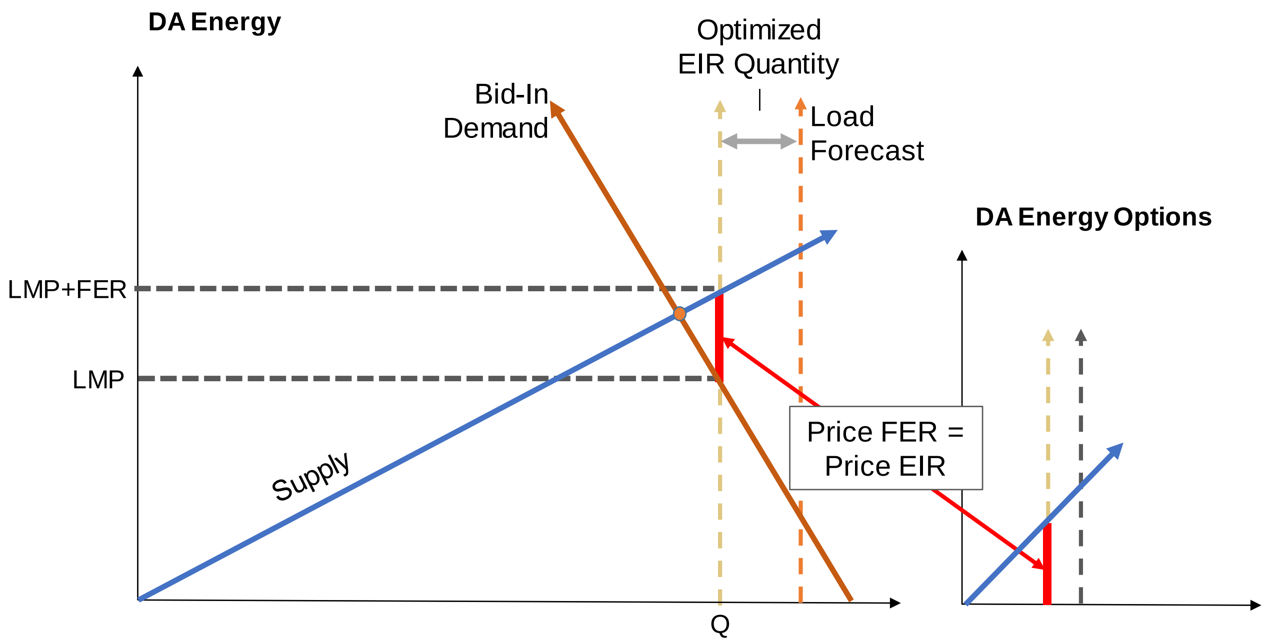
Figure 9. Illustration of the EIR Quantity Under Current Market Rules



Under the ESI Proposal, when determining the quantity of DA cleared energy and EIR, the model balances (on the margin) the cost of additional MW of DA energy with the cost of additional MW of DA EIR energy option. In this tradeoff, the welfare "loss" of additional DA energy is the *difference* between supply offers and demand bids for energy because at this MW quantity, the cost to supply an increment of energy exceeds demand's valuation for it (as represented by its bid price). At the intersection of supply and demand (price "LMP" in **Figure 9**), this loss is zero because supply offers and demand bids are equal. However, total cost of both DA cleared energy and EIR together may not be lowest at this point. In particular, if the market clears the same quantity of DA energy as under current market rules, a large quantity of EIR would be required to meet the load forecast, which would be costly as the market would procure DA energy options to make up this EIR gap.

Figure 10 illustrates the market outcome after co-optimization of DA energy and EIR under ESI. With the co-optimization of DA energy and EIR, total costs can be minimized by adjusting DA energy, which in turn decreases the EIR quantity, until the marginal loss from DA energy (reflecting the difference between the Supply and Bid-In Demand Curves in **Figure 10**) equals the cost of DA energy options, on the margin. As a result, the quantity of DA energy increases compared to the market-clearing quantity under current market rules. In **Figure 10**, this point is represented by the red line where the marginal loss in DA energy equals the marginal DA energy option offer.

Figure 10. Illustration of Interaction between DA Energy and EIR Under ESI



Consistent with the ESI market design, the model solves for both the quantity of DA energy and the quantity of EIR while accounting for this interaction between the DA products. Thus, the analysis provides estimates for the increases in cleared DA physical energy supplies that are expected under ESI due to this co-optimization, which will reduce the gap between cleared DA physical energy supplies and the ISO load forecast, relative to current market rules.

Our analysis also accounts for expected market responses to these shifts in cleared DA energy supply due to ESI co-optimization of ESI products, including these EIR interactions. In particular, the model accounts for adjustments to bid-in demand that would be expected in response to the apparent reduction in LMP between **Figure 9** and **Figure 10.** Because there has been no change in the underlying expected RT LMP, this would appear to offer a persistent and predictable difference between DA and RT LMPs that could offer a profitable trading (arbitrage) opportunity.[25] But, faced with this opportunity to earn positive profits, market participants will increase their bid-in demand for DA energy until their trading activity has competed away these expected profits. To account for this trading activity, we adjust (increase) bid-in demand so that the resulting day-ahead LMPs are consistent with the day-ahead LMPs that cleared under current market rules – that is, those prices that were consistent with expected RT LMPs. This adjustment accounts for the increase in bid-in day-ahead demand that is expected under ESI as a consequence of this dynamic aspect of the EIR constraint.

[25] While we expect changes in real-time LMPs under ESI, these changes to not reflect the changes in LMPs that occur in the day-ahead market if the market clears at an equilibrium where the marginal supply offer exceeds the marginal demand bid.

6. Real-Time Markets

The real-time energy market functions similarly to the DA market described above. Resources offer into the energy market based on their marginal and opportunity costs. The market clears to ensure that demand is met, supply and demand are balanced, and operating reserve constraints are met, while co-optimizing the procurement of energy and operating reserves. The model includes a single 10-Minute Reserve (TMR) product that combines spinning and non-spinning reserves and a 30-Minute Operating Reserves (TMOR). Resources do not provide bids for these reserve products, but rather the system optimizes such that resources provide them based on their claim-10 and claim-30 capabilities (or ramp capabilities for on-line resources) while minimizing energy costs. The requirements in each hour for TMR and TMOR are assumed fixed at 1,600 MW and 2,400 MW, respectively and quantities of MW provided toward TMR cascade into the TMOR requirements. Reserve Constraint Penalty Factors (RCPFs) are set at $1,500 (for TMR) and $1,000 (for TMOR).

Consistent with actual market operations, the RT market clears at inelastic (fixed) load levels, and does not reflect the clearing of supply offers and demand bids, as is the case in the day-ahead market. These realized RT load levels differ from DA demand, reflecting normal daily variation and market uncertainty. We do not model differences in resource availability between day-ahead and real-time markets, although several scenarios explore the impact of shocks to resource availability due to sudden unexpected outage contingencies.

C. Fuel Inventory Constraints

Fuel availability has a significant impact on the energy supplies that certain types of fossil-fuel resources can deliver in real-time during winter months. The model accounts for both natural gas system delivery constraints and resource-specific fuel oil constraints. As described earlier, offer prices from fuel-oil resources with limited fuel supplies reflect these constraints through the opportunity costs adders that support the delivery of this energy when it is most valuable. In addition, the quantity of supply that can clear from these resources for DA energy or ESI product awards (and RT energy and operating-reserve supply) are constrained by physical inventory available at the start of the day. The analysis also accounts for system and resource-level fuel constraints in winter and non-winter months, although given the lower level of LDC natural gas demand these constraints generally have no material impact on market outcomes during non-winter months.

1. Natural Gas Market Assumptions

Natural gas is used extensively for residential and commercial heating in New England during the winter, and is drawn off interstate gas pipelines for residential distribution by LDCs. Gas-fired power plants draw their fuel supply off the same interstate pipelines but generally have interruptible contracts with fuel suppliers. As a result, during cold winter days, less natural gas is available for use by electrical generators. In the model, the natural gas available for electrical generation on any given hour is calculated as the total potential injections into system from the interstate pipeline system and LNG terminal supplies less the demand for natural gas from LDCs:[26]

[26] Natural gas available for generation is "shaped" across the hours of a day to allow for greater gas use during hours of peak electrical demand. No geographic constraints are modeled.

$$\textit{Natural Gas Available for Generators}$$

$$\leq \textit{Interstate Pipeline Capacity} + \textit{LNG Terminal Supply} - \textit{Net LDC Gas Demand}$$

Our gas availability analysis is based on natural gas pipeline capacity and LDC demand (by temperature) data and models provided by ISO-NE, and is consistent with the Fuel Security Review for FCA 14.[27] Pipeline capacity into ISONE is assumed to total 3.59 Bcf/day, which includes capacity for Algonquin, Iroquois, Tennessee, and Portland. This pipeline capacity takes into account capacity expansions by 2025 and subtracts gas under "pass-through" contracts that flow to Long Island. LDC demand by temperature is modeled using the ICF model from the FCA 14 Fuel Security Review. LDC demand increases, and gas available for generation drops, when ISO-NE hub temperature falls.[28] Thus, in the Infrequent Case, more natural gas is available for electric generation than in the Frequent Case, since the ISO-NE hourly temperature is higher on average.

In the Central Cases, we assume that the region's available LNG supply is consistent with (1) the estimated delivery capability of the Canaport LNG facility to New England, and (2) the exit of the associated LNG terminal owned and operated by Distrigas of Massachusetts (DOMAC).[29] This assumption may either under- or overstate the likely supply of LNG under Central Case conditions. While potential supply from Canaport may not be fully contracted at present, the assumed exit of DOMAC would increase demand for supplies from remaining sources of fuel supply.

LDC gas demand is modeled as a function of temperature based on ISO-NE modeling, and accounts for satellite LNG storage withdrawals.[30] The natural gas supply available to the electricity sector after accounting for these supplies and uses is in **Figure 11**.

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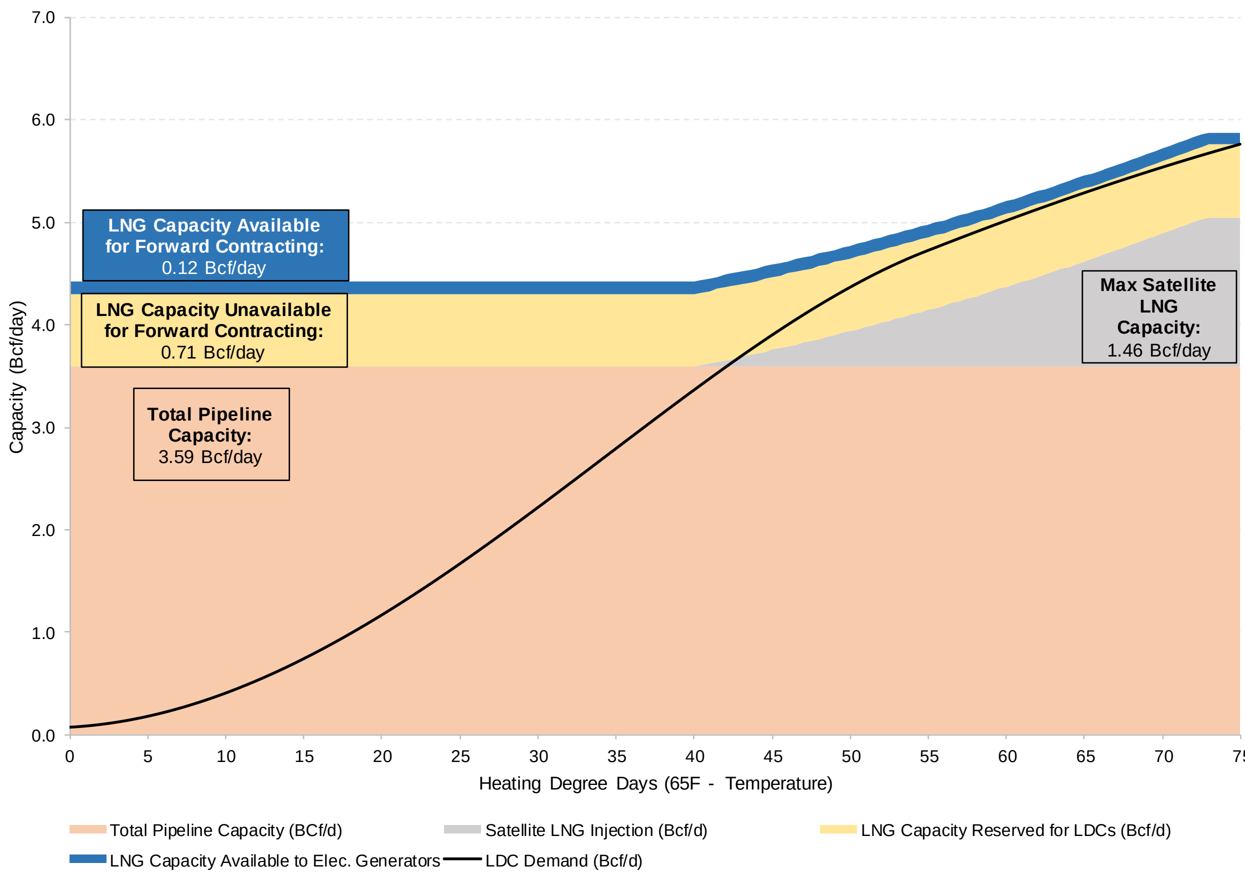
27 Sproehnle, Norman, "Forward Capacity Auction 14 (FCA 14): Fuel Security Review Inputs Development," March 29, 2019.

28 LDC demand for pipeline gas is also offset by injections from satellite LNG facilities, which vary by temperature as well.

29 Deliverable LNG supplies from Canaport capacity are by the transport capacity of the Maritimes and Northeast Pipeline.

30 Sproehnle, Norman, "Reliability Reviews for Fuel Security: Model Inputs, Results, and Criteria for Unit Retention in the Forward Capacity Market (FCM)", July 31, 2018. https://www.iso-ne.com/static-assets/documents/2018/07/a2_1_iso_presentation_reliability_reviews_for_fuel_security.pptx

Figure 11. Natural Gas Supply and Demand by Heating Degree Day



In response to ESI's incentives, we assume in the ESI cases that certain gas-only generation units enter into forward contracts with an LNG terminal. Under these forward contracts, the contract holder can purchase natural gas at an agreed-upon commodity price, assumed to be $10 per MMBtu, on 10 days over the course of the winter. These contracts do not increase the aggregate supply of natural gas available to the electricity sector, as we assume that the LNG terminals supply fuel to the market at their full transmittable capacity.[31] However, the forward LNG contracts do reduce the cost at which fuel is procured, which can lower the marginal cost of power supply for resources with these contracts. Thus, the forward LNG contracts can affect LMPs, and in turn affect customer payments. To the extent that ESI would incent contracts with LNG terminals for supplies that would otherwise not be brought to the region, the Impact Assessment would tend to understate the reliability benefits of ESI, all else equal.

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31 The structure of this contract does not have a material effect on outcomes of the Impact Assessment. The assumed commodity price ($10 per MMBtu) for the contract is most consistent with a call option contract, in which the contract holder has the right, but not the obligation, to take supplies. If a take-or-pay contract were assumed, the commodity cost would likely be lower, which would lower production costs and potentially LMPs in certain hours, but otherwise leave market outcomes unchanged.

Daily natural gas prices in each case are the unadjusted historical base year prices for Algonquin natural gas for the given day (where the historic DA price is assumed for both DA and RT), and used in conjunction with unit heat rates to determine fuel costs for natural gas and dual fuel units. Our natural gas market analysis does not attempt to calculate a general equilibrium price and quantity for each day based on natural gas demand and availability which both differ with temperature and gas prices.

2. Liquid Fuel Price, Storage, and Refill Assumptions

Supply from oil-only and dual-fuel units running on oil are constrained by the amount of fuel oil that is in their storage tanks at the beginning of each hour. The model maintains an accounting of fuel in inventory (storage tanks) for each unit given its initial inventory, subsequent use to generate power and replenishment of inventory ("refueling"). Inventory levels are updated fir each operating day.

Each oil-only or dual-fuel unit starts the winter (or other modeling period) with an initial inventory that is drawn down if the unit is called on to generate in the energy market. If the inventory falls below a unit-specific "trigger quantity," then the unit receives a replenishment shipment of liquid fuel (equivalent to a number of tanker truck or fuel barge loads) after a specified order lead time. Unit replenishment behavior (i.e. initial inventory, trigger quantity, etc.) is assumed to differ across units based on the means of replenishment (tanker or barge), maximum tank size, and other characteristics. **Figure 12** shows an illustrative example of how these parameters are triggered throughout a winter, modeling the fuel inventory of a specific resource on each day.

Figure 12. Illustrative Fuel-Level Chart

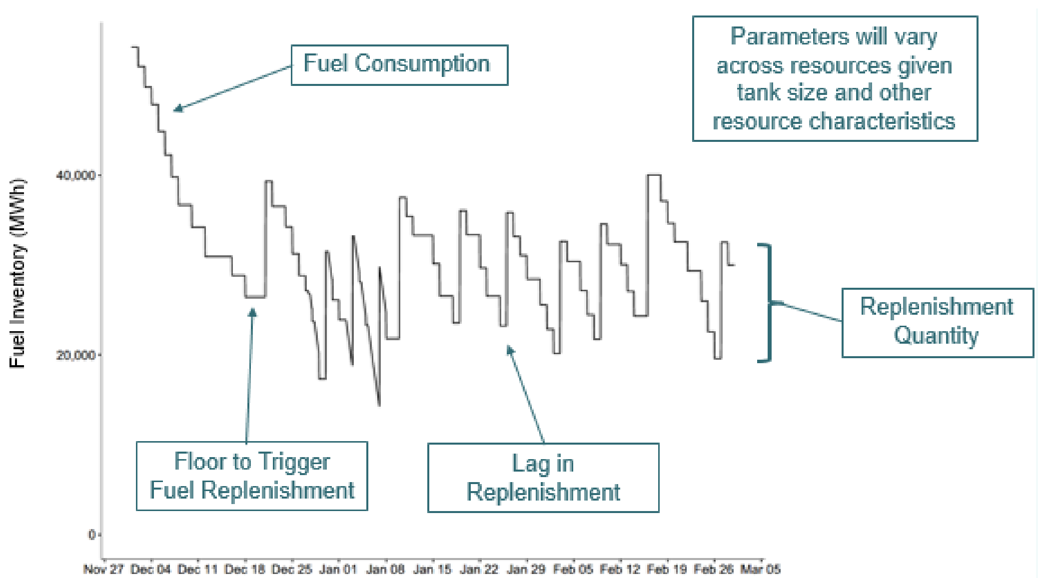


Table 6 summarizes the parameters used in each unit's fuel replenishment model. These parameter estimates are based on a combination of sources, including the ISO-NE fuel surveys, discussions with system operators and other New England market participants, and experience with fuel security analysis in other regions.

Table 6. Refill Quantities and Capabilities

Refuel Type		Truck			Barge
Size		**Small**	**Medium**	**Large**	
Unit Tank Storage Capacity (days)		(0 - 1]	(1 - 3]	(3 +)	(0 +)
Initial Fuel Inventory	CMR	December 2018 Inventory			
	ESI	CMR Fuel Levels + Incremental Inventory			
Rate of Fuel Delivery (gals per day)	CMR	123,750	123,750	123,750	375,000
	ESI	165,000	165,000	165,000	500,000
Last Refill Date		2/28/2026	2/28/2026	2/28/2026	2/14/2026
Order Lead Time (days)		1	1	1	4
Refill Threshold (percentage of initial inventory)		70%	40%	30%	10%

Note: [1] Rates of fuel delivery are based on delivery capability and shipment quantity.

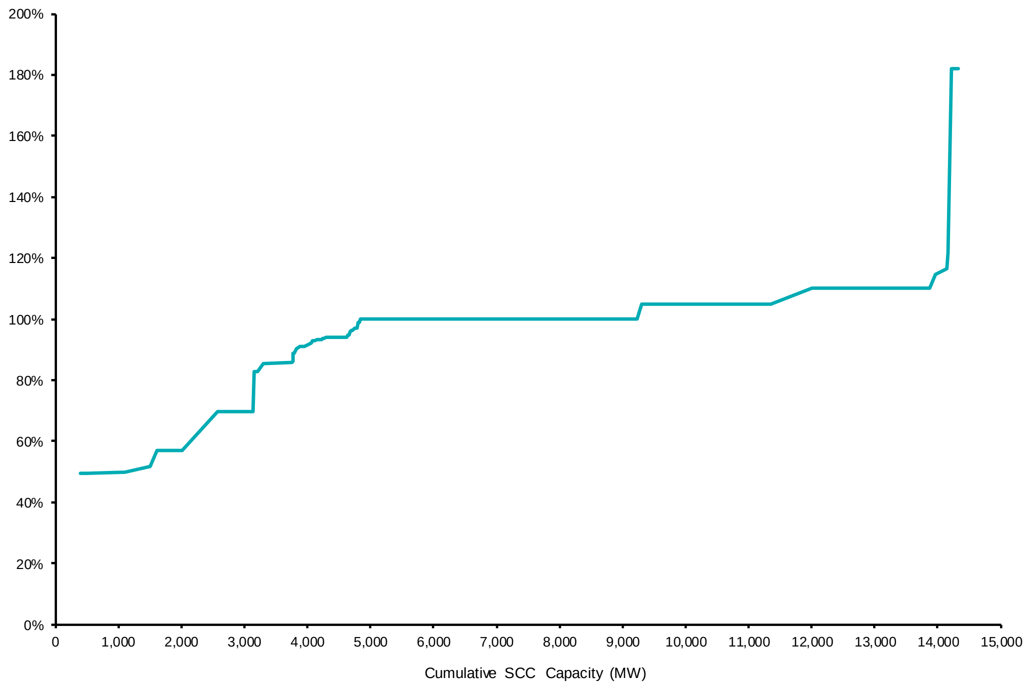
The maximum liquid fuel storage capacity for oil and dual fuel units is based on historical unit-specific fuel survey data from ISO-NE. Units are assumed to enter the winter modeling period with a winter starting fuel quantity that is a fraction of their maximum fuel storage capacity, again based on historical fuel survey data.[32] Under CMR, each unit's starting inventory is based on December 2018 inventory, when the Winter Fuel Program was not in effect.

The incentives created by the ESI proposal are expected to change these fuel inventory and refueling decisions. Under ESI, we assume the units start with winter with a larger initial inventory than in the CMR Case. Initial inventories under ESI are set using information on initial (December) inventory levels from years when ISO-NE's Winter Program was in effect (winters of 2014 to 2017). These Programs compensated resources for increasing stored fuel supplies, with compensation mechanisms differing across the years the Programs were in effect. Thus, the initial inventories held during these winters reflect the market's response to the incentives created by the earlier winter Programs, and are a reasonable starting point for an expected response to ESI.

Using the average initial (December) inventory as a starting point for calculating assumed initial fuel inventories under ESI, we make subsequent adjustments (above or below the 2014-17 Winter Program levels) to account for a number of factors. In particular, units with low a marginal generation cost were assumed to hold more fuel (relative to other units), as these resources are more competitive at supplying DA energy and DA energy options; certain units with very large storage tanks (relative to capacity) were assumed to hold less fuel than was held during the Winter Program periods, as less benefit was observed from incremental inventory; and some units with small tanks (relative to capacity) were assumed to hold more fuel, when historical December inventories were relatively low. **Figure 13** illustrates this variation in initial inventory, showing the ratio of (1) assumed initial inventory under ESI to (2) the average Winter Program initial inventories (December 2014 to 2017).

32 Units with storage enter the modeling period with as much liquid fuel as they held during Winters 2016/17-2017/18, when the ISONE Winter Fuel Program was in effect.

Figure 13**. Initial Fuel Oil Inventory under ESI**
Assumed Initial ESI Inventory Relative to 2014-17 Average December Storage



Within the model, fuel inventories start at the initial level and are reduced as the resource consumes fuel to supply energy in real-time. Fuel inventories are drawn down until fuel stock declines below a unit-specific refueling threshold that is set as a fixed fraction of initial inventory. When inventories fall below this threshold, refueling occurs. Both the refueling threshold and the refill rate – i.e., the quantity of liquid fuel (per day) – depend on how the resource is refueled (tanker or barge) and size of the unit's fuel tank. For example, units that refuel by barge will refuel less frequently but with a larger quantity per refill compared to units that refuel by truck. In all cases, units will never refuel to a level greater than their initial inventory.

Along with the changes to initial inventory levels discussed above, we also assume changes to the refueling strategies used by market participants in response to the ESI's incentives for increase energy inventories. In particular, we assume that under ESI fuel-oil resources refuel at a faster rate (i.e., more fuel per day), one-third higher than in the CMR case. This assumption is designed to reflect the potential responses of market participants to the incentives created by ESI.[33]

Assumed fuel oil prices are the unadjusted monthly Chicago Mercantile Exchange (CME) futures contract prices as of August 2019 for delivery months as far into the future as possible. If a unit is modeled to run on liquid fuel in a given hour, fuel costs are based on fuel replacement cost at the time it is burned, not the original purchase price of the fuel.

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[33] The assumed change in refueling rate is consistent with the range of different daily refueling rates observed among resources currently within the market.

D. Market Settlement & Model Outputs

The model determines production of electricity in each hour, including day-ahead and real-time prices, quantities of day-ahead and real-time products supplied by each resources, and various resource- and system-level variables related to energy inventory and aggregate fuel use. These outputs are used to develop summary metrics for each cases and scenarios, including: market price and payment impacts, energy mix, and fuel system operational metrics. These outcomes reflect the two-part settlement process used in the New England markets. Impacts are then calculated by taking differences outputs between CMR and ESI cases.

1. Market Price Impacts

Hourly market clearing prices (e.g., LMPs in the energy market) are simulated for the DA and RT markets. Differences between DA and RT clearing prices for energy reflects many potential factors, including: incremental energy inventory available to meet DA and RT energy demand; substitution in resource-level awards between energy and DA energy options; and/or changes in opportunity costs given fluctuations in resource-level energy inventory.

Hourly clearing prices for energy market products are set using the same approach as the current (and proposal) market algorithms. For DA energy, ESI products, RT energy, and RT operating reserves, prices are set at the respective shadow price for the relevant product constraint. The shadow price measures the cost to the system of obtaining an additional MWh of the given product. In cases where an incremental MWh of a product can be procured from the marginal resource, the shadow price is the same as the product offer from that resource. In instances when the incremental MWh is met through a change in supply from committed or uncommitted resources, the shadow price will reflect the increase in cost associated with this change in supply.[34] Examples of this market clearing logic can be found in various ISO-NE presentations.[35]

2. Customer Payments

Customer payments are estimates for each case, reflecting (1) net payments for energy, including DA payments and settlement of RT deviations; (2) FER payments; and (3) the payments for ESI products, including the DA purchase of energy options and the settlement of these DA energy options against RT LMPs. The model does not consider any changes in payments to other ISO-administered wholesale markets such as the Forward Capacity Market or the Forward Reserve Market. Changes in payments potentially reflect a few factors, including the changes in energy supply, due to the effect of ESI incentives on energy inventories, substitution among resource-level awards that shifts the mix of resources mix supplying energy, and the procurement of additional reliability services.

DA and RT energy payments are calculated based on the sum of all cleared day-ahead positions (DA LMP * quantity), minus any deviations in real-time position at the RT LMP. This cost component is calculated in the

[34] Since resources do not provide offers for RT operating reserves, shadow prices for these products are set based on the redistribution of product commitment, rather than a RT operating reserve offer from a marginal resource.

[35] ISO NE, "Winter Energy Security Improvements: Market-Based Approaches", May, June, and July 2019.

same fashion under both CMR and ESI, however payments differ between the two cases because of differences in the overall market solve results.

Forecasted Energy Requirements payments are made to resources supplying energy when their energy supply contributes to meeting the FER. This occurs when there is a positive EIR or when the EIR is exactly zero (such that increasing the EIR by 1 MW would require additional energy to avoid making EIR payments). The total FER payment is the EIR price times the quantity of DA energy awards.

Net ESI product payments reflects two components. The first component is the payment to generators for supplying DA energy option to meet ESI product demand. This payment is equal to the market-clearing price of the DA energy option for each ESI product times the quantity of DA energy options needed for each ESI product.

The second component accounts for settlement of the DA energy options against the RT LMP. Load is paid the option closeout cost by DA energy options suppliers. The option closeout cost is RT LMP minus the strike price if the RT LMP is greater than the strike price, while the closeout cost is zero if the RT LMP is less than the strike price. Closeout costs are estimated by settling historical RT LMPs against the strike price.[36] The net cost of the ESI products thus reflects these upfront option payments net of real-time settlement.

3. Changes in Production Costs and Energy Mix

The model analyzes changes in production outcomes, including production costs and clearing resource mix. Production costs include both modelled variable production costs, including fuel, variable operations and maintenance, emissions, and fixed costs of production, represented as changes in costs associated with taking action to secure fuel incentivized by the proposed ESI rules. These fixed costs include the holding costs associated with larger end-of-winter fuel inventories and upfront LNG forward contract costs.

4. Operational and Reliability Metrics

Our production cost model is not designed to provide a thorough or complete analysis of the impact of ESI on potential reliability outcomes. Such impacts are typically performed through other modeling techniques and may reflect different assumptions about a variety of factors that would impact reliability outcomes. The model does not account for full range of contingency events that can affect resource, transmission and fuel availability, and moreover does not consider the risks posed by such contingencies during acute periods of system stress due to constraints on fuel supplies. Our analysis also does not account for transmission topology, which can capture the locational limits and constraints that can lead to reliability concerns in particular zones or load pockets. Furthermore, our model does not model plant commitment and dispatch and other intertemporal limits to plant operations (e.g., minimum run times and minimum down times). As a result, our model assumes smoother and more continuous plant operations than occurs under actual system operations. Finally, the

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[36] We calculate energy option prices and settlement using the same underlying historical distribution of prices. For estimating prices and settlement of financial derivatives, the larger time-series available through historical data provides a more reliable approach than reliance on real-time prices from our production costs model. And, settling an option priced using historical data with prices from a different mathematical framework (i.e., our production cost model) would could create an internal inconsistency, making the prices invalid and the causing the resulting settlement to have excess (or insufficient) returns. Further, production cost models generally understate market volatility, unless calibrated to capture such volatility, which our model is not.

model seeks to evaluate the expected market impacts of ESI and assumes a market response to stressed conditions, such as additional fuel procurements and improved fuel supply chain logistics, especially under the ESI scenarios where the incentives to make such procurements are increased because of the additional revenue associated with the new ancillary services.

Due to the combined impact of these factors, we would expect our model to understate potential reliability risks associated with any market simulation, including the potential for reserve shortages, and thereby underestimate potential reliability benefits of the ESI proposal. Despite these limitations, we analyze several metrics related to fuel systems operations that potentially provide information related to reliability outcomes. Along with operating reserve shortages, we also measure several outcomes related to the use of the natural gas supply system and fleet-wide fuel oil inventory.

IV. Impact of Energy Security Improvements on the Energy Market

The proposed ESI market rule changes would create new ancillary services that are expected to improve both efficiency and reliability by addressing gaps in the current market. In this section of the report, we summarize the results of our assessment of the impact of the ESI proposal on the ISO-NE energy markets. Our assessment includes both quantitative estimates of impacts based on the production cost model and qualitative analysis developed through economic and market analysis. The analysis quantifies the expected impacts for particular scenarios reflecting assumptions about market and system conditions. It also illustrates the mechanisms through which the proposed market rules will impact market outcomes.

Below, we summarize the key findings with respect the changes in market outcomes expected to be caused by ESI:

1. Consistent with its design, ESI creates incentives for resources to maintain more secure energy supplies (e.g., higher levels of energy inventories) than under current market rules. These incentives are created through two channels: FER payments for resources supplying DA energy, and revenues to compensate resources that supply the new ESI products. Sections IV.A.1 and IV.A.2 discuss these incremental sources of revenue, while Section IV.A.3 analyzes the incremental incentives to support energy inventory.
2. ESI provides efficient price signals to procure the new DA ancillary services. Procurement of DA energy and these new ancillary services is co-optimized, ensuring that services are procured at least cost and that price signals are efficient and consistent with these positions. Our analysis reflects the gains from this co-optimization and the resulting substitutions between these products supplied by different resources, given the relative cost of supply DA energy and DA energy options.
3. ESI may cause shifts in way resources participate in the DA markets that enhances energy security by preserving energy inventory. With ESI, these resources are compensated for maintaining energy supply in reserve, rather than using limited inventories to supply energy, which is the only source of compensation under current market rules. Section IV.A.2 discusses expected shifts in the mix of energy supplies under ESI.

4. Under ESI, the day-ahead market would be less likely to clear energy supplies that are less than the forecasted load, as compared to current market rules. And, any remaining gap between cleared supplies and forecast load will tend to be smaller with ESI. This outcome is a consequence of the auction clearing mechanism under ESI, which will lower the cost of meeting the FER by procuring additional DA energy. Section IV.2 shows how these shifts in DA energy supply are expected to occur under ESI.

5. ESI can improve efficiency and lower production costs under stressed market conditions when the increase in energy inventory can avoid production on higher cost fuels.

The ESI proposal will also have consequences for the flow of payments by load (and net revenue to resource owners) in the ISO-NE energy markets:

A. Aggregate payments by load to suppliers will be affected by ESI, although these impacts vary with market conditions. When stressed conditions are uncommon (e.g., the Infrequent Case), ESI increases payments to generators from loads. However, with stressed conditions, the impacts depend on the offsetting effects of increased payments for ESI ancillary services, on the one hand, and reductions in energy costs that would occur from the availability of additional energy inventory supplies during tight market conditions, on the other. Thus, changes in payments under stressed conditions depends on a combination of factors, such as the nature of the stressed conditions (e.g., frequency of stressed conditions and duration of these conditions) and the market's response to ESI incentives. **Table 7** summarizes this change in payments.

Table 7. Summary of Change in Total Payments, Central Case

		Frequent Case				Extended Case				Infrequent Case			
Product / Payment		**CMR**	**ESI**	**Difference**		**CMR**	**ESI**	**Difference**		**CMR**	**ESI**	**Difference**	
Energy and RT Operating Reserves	[A]	$4,101	$3,917	-$183	-4.5%	$2,730	$2,516	-$214	-7.8%	$1,749	$1,707	-$41	-2.4%
DA Energy Option													
DA Option Payment			$207				$113				$45		
EIR			$0				$1				$1		
RER			$67				$37				$15		
GCR10			$93				$50				$20		
GCR30			$47				$25				$10		
RT Option Settlement			-$142				-$81				-$31		
Net DA Ancillary	[B]		$66				$32				$15		
FER Payments	[C]		$250				$113				$61		
Total Payments	[A+B+C]	$4,101	$4,233	$132	3.2%	$2,730	$2,661	-$69	-2.5%	$1,749	$1,783	$35	2.0%

B. Changes in net revenues vary across resource types, although direction of these impacts (i.e., whether net revenues increase or decrease) is generally the same across resources within each Case (i.e., given the nature of the stressed market conditions).

C. Estimated impacts reflect only energy and ancillary services market outcomes, and do not consider any changes in payments (and net revenues) associated with FCM or FRM that potentially occur, for example, due to changes in the net cost of new entry or changes in the FRM design.

The following sections detail these results, evaluating price and incentive effects, the supply of DA energy and ESI products, production costs, total payments, net revenues and operational outcomes. We first discuss the winter cases, and then discuss the non-winter cases. Unless otherwise stated, differences or changes discussed in the sections that follow refer to differences between the ESI and CMR cases.

A. Winter Cases

1. Prices and Incentives for Energy Supply

The ESI proposal would have a number of dynamic effects on day-ahead market-clearing prices. Along with introducing new ancillary service products, LMPs for DA energy will be affected given the complex interactions among day-ahead products under the proposed design. The resulting price signals would create incentives for resource owners to efficiently supply services to the region, particularly reliable delivery of energy supply in real-time. Thus, in this section, we consider these price effects and their effects on incentives in tandem.

In principle, improvements in the reliable supply of real-time energy can be made through many actions. Our quantitative analysis considers improvements in energy inventory, including increasing the quantity of liquid fuel held in on-site storage tanks and contracting for more-firm delivery of fuel, such as through a forward contract with an LNG terminal. But, ESI's incentives would affect many other types of actions that would have consequences for resources' ability to supply energy in real-time, such as preservation of limited energy inventories (e.g., at hydropower facilities), investment that expands potential fuel storage (e.g., retrofitting gas-only plants for dual-fuel), general improvements in operational performance (e.g., other contractual arrangements for fuel, reducing forced outage rates), and the internalization of the potential ESI revenues (and costs) in entry and exit decisions.

For each of these decisions, resource owners go through a process of balancing various tradeoffs that have implications for the reliability of energy supply in real-time. For example, owners of resources with stored fuel supplies would balance the costs of investing in additional energy inventory against the benefits of this additional investment, in terms of increased market returns. When making this assessment, ESI would increase generator incentives to secure energy inventory relative to current market rules through two new sources of return.

- ***FER payments***. FER payments would provide incremental revenues to resources supplying DA energy. Thus, as resource owners balance the tradeoffs to holding additional fuel inventory (at the margin), FER payments would increase the return to holding additional inventory compared to current market rules, causing them to increase inventory. These decisions to hold additional inventory would manifest themselves in an increase DA energy supply when the supply a resource might otherwise offer may be limited by its inventory. Such increases in supply are most likely to occur during stressed market conditions, when fuel supplies are most limited and the gains (increased revenues) from holding fuel supply are greatest.
- ***ESI products.*** By providing a means to monetize the value of energy inventory, the sale of DA energy options to satisfy ESI product requirements provides a means for resources with energy inventory to earn a return on energy inventories, even if energy inventory (i.e., fuel supplies) are not consumed. Thus, at the margin, holding more fuel supply than resources otherwise would under current market rules provides additional revenue streams through the sale of DA energy options.

  Along with providing the capability to support a DA energy option through the delivery of real-time energy, energy inventory can lower the financial risk faced by a resource when offering a DA energy option. Thus, a resource with energy inventory can submit a more competitive offer for a DA energy option, making it more likely to receive these awards. In turn, the financial risk, and therefore financial cost, is reduced when taking a DA energy option award, providing a greater return to the energy option award.

The quantitative analysis in Section IV.1.c) and Section IV.1.d) illustrate the benefits of additional revenue streams created by ESI to support incremental energy inventory.

a) Payments to DA Energy Supply

Under ESI, the payments to resources that supply DA energy would undergo several changes compared to current market rules.

First, under ESI, resources awarded DA energy positions earn FER payments, in addition to the LMP. FER payments are incremental payments made to compensate generation for helping to meet the EIR requirement. The addition of these payments awards resources that supply energy for contributing to meeting the FER requirement and ensures that resources supplying energy are no worse off for supplying DA energy rather than a DA energy option (i.e., the awards are incentive compatible).

Second, ***with the EIR constraint, the market will clear a larger quantity of DA energy under ESI compared to current market rules***. This impact is discussed below in Section IV.2. Because LMPs are set based on demand bids (rather than supply offers) when the EIR constraint impacts market clearing, LMPs *decrease* as the supply of cleared DA energy increases. (As described above, FER payments provide the additional compensation so that all supply is compensated at no less than its offer, which may be prices above demand bids at the point of market clearing). But, reductions in LMPs will tend to be more than offset by FER payments when these adjustments occur. Thus, all else equal, payments to energy will increase with this adjustment.

Third, co-optimization of all products in the day-ahead market can also lead to substitutions among products that can affect market-clearing for DA energy. Because the optimization needs to satisfy constraints for each DA product, the cost-minimizing (welfare optimizing) solution awards positions for each service to resources depending on their offer prices *relative to* the offers from all other resources for each of the services. For example, a more costly DA energy offer may clear over a lower DA energy offer if the resource with the lower energy offer creates more cost savings by supplying a DA energy option rather than DA energy.[37] In addition, given differences in energy inventories and different substitution possibilities, opportunity costs for energy limited resources (in both DA and RT) will differ between the ESI and CMR cases.

Each of these impacts is driven by changes to market-clearing with the addition of the new ancillary services. But, we also expect ESI's incentives to lead to an increase in energy inventory. In turn, this increase in the supply of energy in the market to meet DA energy demand would be expected to *reduce* LMPs, all else equal.

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[37] For example, assume Resource A can supply DA energy at $50 per MWh and a DA energy option at $12 per MWh, while another Resource B can supply DA energy at $45 per MWh and a DA energy option at $5 per MWh. Under CMR, Resource B would supply DA energy first due to its lower offer; but, under ESI, if the system requires one resource to provide energy and the other energy options, the optimization would award Resource A energy and Resource B energy options because the total cost of doing so ($55 = $50 for A's energy plus $5 for B's option) is less than the alternate scenario where lower cost B supplies the energy ($57 = $45 for B's energy plus $12 for A's option).

This indirect effect, the reduction in LMPs, would be expected to dampen the direct of ESI's incentives. But, such "equilibrium" adjustments by the market to new incentives occur with any change in policy or regulation.

Table 8 provides the change in payments to energy for the three Central Cases in ESI compared to CMR. Changes reflect both the change in LMPs and the additional FER payments. Across all three Cases, DA LMPs are reduced by $1.20 per MWh (Infrequent Case) to $6.43 per MWh (Extended Case). These LMP changes are the result of the combination of factors identified above, although the most important factor is the incremental energy inventory that the model assumes under ESI.

In the Infrequent Case, after including the FER payments, total payments to DA energy increase by $0.74 per MWh in the Infrequent Case. Without any periods of system stress, the additional supply of energy inventory incented by ESI has no downward effect on LMPs. Consequently, compensation to energy supply for its contribution to meeting the FER leads to an increase in net payments to energy.

In the two Cases with stressed conditions, we find different impacts: in the Frequent Case, average net payments to DA energy increase by $2.27 per MWh, whereas, in the Extended Case, average net payments decrease by $2.88 per MWh. In both of these cases, additional energy supply incented by ESI has a downward effect on LMPs. In the Extended Case, this downward LMP effect outweighs the cost of compensating for contributions to meeting the FER, resulting in a net reduction in payments per MWh. In the Frequent Case, however, the payments for FER outweigh the reductions in LMPs.

Table 8. Average DA Payments to Generators
CMR vs ESI ($ per MWh)

	CMR	ESI				Change	
Case	Day-Ahead LMP [A]	Day-Ahead LMP [B]	FER [C]	Day-Ahead LMP+ FER [D]=[B]+[C]	Real-Time LMP [E]	Day-Ahead LMP [B]-[A]	Day-Ahead LMP + FER [D]-[A]
Frequent Case	$127.40	$121.91	$7.76	$129.67	$121.60	($5.49)	$2.27
Extended Case	$85.15	$78.72	$3.55	$82.27	$79.73	($6.43)	($2.88)
Infrequent Case	$54.97	$53.77	$1.94	$55.71	$55.86	($1.20)	$0.74

b) Prices for ESI Ancillary Services

The ESI proposal introduces new DA energy option products to the New England energy markets. **Table 9** reports average award prices for these products for the Central Cases. These prices are weighted averages, reflecting the quantity of each product needed in each hour. These quantities are assumed to be the same in all hours for GRC10, GRC30 and RER, although in actuality these quantities may differ from hour to hour. By contrast, the quantity of EIR procured in each hour is dynamically determine by the model (through the substitution of DA energy for EIR), varies from hour-to-hour, and is zero in a large fraction of hours due to the ESI design in which additional DA energy supply can substitute for EIR.

Table 9. Average DA Energy Option Clearing Prices

($ per MWh)

Case	EIR/FER	GCR10	GCR30	RER
Frequent Case	$69.11	$27.03	$27.03	$26.97
Extended Case	$47.74	$14.51	$14.45	$14.45
Infrequent Case	$8.36	$5.77	$5.75	$5.75

Note: Unweighted average across all hours.

Average prices for GRC10, GRC30 and RER vary due to differences in resources' ability to supply each product. For example, because fewer resources are able to receive a GCR10 award, as compared to the other DA energy options, these prices are higher, reflecting the need to accept higher priced offer to meet the GCR10 requirement in some hours.

Prices vary across Cases, driven by several factors. First, the quantity of DA supply (energy and energy options) differs across cases, with the largest quantities in the Frequent Case and the smallest quantity in the Infrequent Case. When a larger DA supply is needed, prices will be higher, all else equal, because the market clears at a higher point on the DA energy and DA energy option supply curves. At the extreme, DA energy option product shortages may occur (priced at the penalty factors). Thus, Cases with higher DA energy option product prices are due, in part, to a larger number of RER shortages. Second, expected closeout costs are highest when price volatility is greatest. Thus, the option prices are greatest in the Frequent Case, with more frequent periods of price volatility than in the winters in which volatile market conditions are less frequent.

Average EIR prices differ from the other ESI products because the quantity of EIR procured varies from hour to hour, and because EIR prices tend to be largest in hours in which the EIR quantity is largest (i.e., EIR prices and quantities are positively correlated). **Table 10** provides further detail on the different outcomes for EIR/FER prices. The EIR/FER price is greater than zero whenever the EIR constraint is binding. But, this constraint can bind when the EIR quantity is greater than zero and when it is *exactly* equal to zero. The latter case occurs when the auction mechanism substitutes DA energy for EIR until EIR is exactly equal to zero, but the constraint continues to bind because increasing the load forecast would cause an immediate gap between cleared energy and the load forecast. Thus, DA energy should be compensated for keeping the EIR at zero.

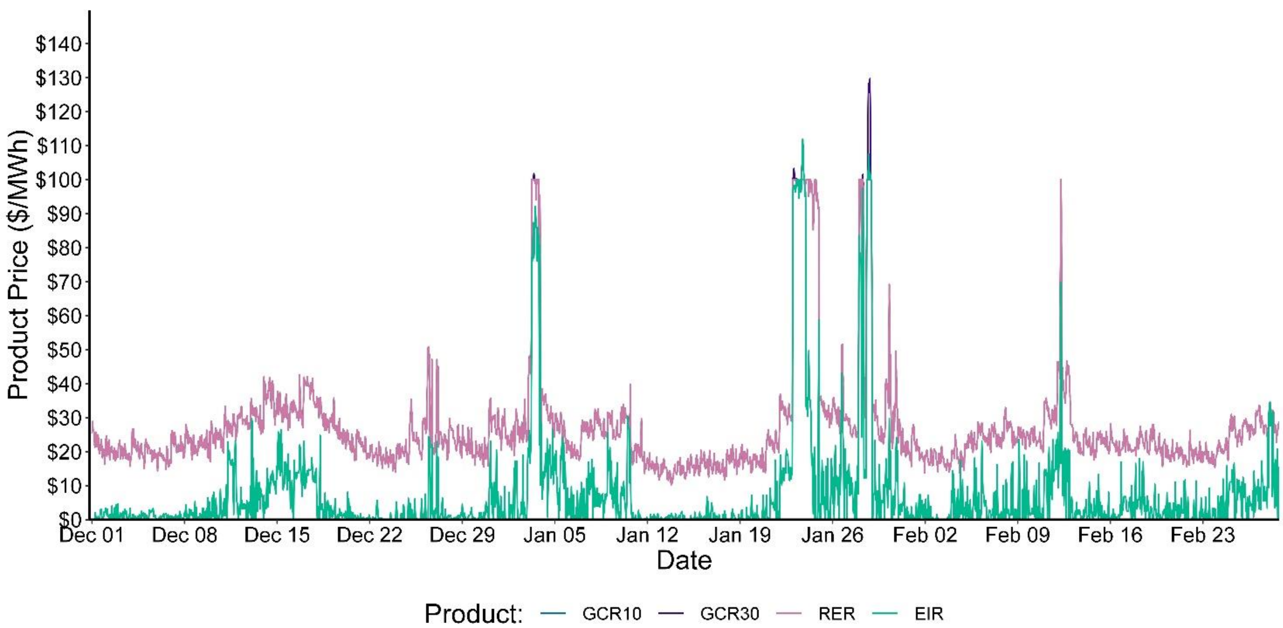
After accounting for adjustments to the EIR due to substitutions of DA energy for EIR, there is a positive quantity of EIR in a relatively small share of hours, ranging from 3% in the Frequent Case to 16% in the Infrequent Case. Hours when EIR is "exactly" zero but the EIR price is positive represents a large fraction of hours, ranging from 42% in the Extended Case to 72% in the Frequent Case. Hours in which cleared energy is greater than the forecast accounts for the remaining hours – 24% in the Frequent Case to 51% in the Extended Case.

Table 10. Frequency of EIR Quantity-Price Outcomes by Case

ISO Forecast Load minus Cleared Energy Supply	EIR Quantity	EIR/FER Price	Frequent Case	Extended Case	Infrequent Case
> 0	> 0	> 0	3%	7%	16%
= 0	= 0	> 0	72%	42%	45%
< 0	= 0	= 0	24%	51%	39%

The average prices in **Table 9** mask hourly variation in prices within Cases. **Figure 14** illustrates this hourly variation for the Frequent Case. As we describe below, this hourly variation is an important element of the ESI proposal, as it signals periods of greatest need for energy inventory and compensates resources able to provide supply during these periods.

Figure 14. Estimated ESI Product Prices by Hour, Frequent Case



c) Incentives for Investment in Incremental Fuel Oil

ESI creates incentives for market participants to improve their ability to deliver energy in real-time. Owners of resources that rely on fuel oil can increase the reliability of their real-time energy delivery by increasing the quantity of fuel the keep in inventory. In making decisions about the quantity of fuel to keep in inventory, owners must balance the costs and benefits of holding fuel. On the one hand, holding fuel inventory incurs additional costs given the risk that such inventory will need to be held for an extended period of time. On the other hand, additional fuel inventory may affect the resource's ability to supply and its costs and (risks) of taking day-ahead positions. At present, these benefits are driven by the opportunity to earn margins (revenues in excess of costs) for selling power. With ESI, these margins would be increased by the FER payments and additional returns earned through the sale of DA energy options.

To assess the magnitude of these incentives, we start by comparing these new ESI revenues to the change in inventory costs, given the quantity of incremental fuel ESI is assumed to incent. New revenue streams that are large relative to the change in inventory costs is an important indicator of the proposal's strong incentives. **Table 11** to **Table 13** provide this comparison. New ESI revenue streams include FER payments and DA energy options. In these calculations, the DA energy option revenues reflect only the risk premium component of the marginal offer that sets the clearing price, but not the remainder, which corresponds to the expected closeout cost that the generator expects to pay back (on average) to load in the second part of the option settlement. Also shown is the change in economic costs of incremental energy inventory, measured by the financial ("holding") costs of having more fuel in inventory at the end of the winter because of decisions to increase inventory during the winter.

The tables demonstrate that the average incremental payments to resources under ESI generally far outweigh the additional holding costs. In the Frequent or Extended cases, these ESI revenues far exceed the change in holding costs for all fuel-oil resource categories. For example, for Dual Fuel, Combined Cycle Units in the Frequent Case, the incremental cost of holding a larger quantity of fuel at the end of the winter because of more aggressive refueling is $14 per MW. By contrast, the additional revenues earned because of ESI compared to current market rules are $5,591 per MW ($5,452 and $139 per MW for FER payments and DA energy options, respective), for a net increase in revenue of $5,577 per MW. These results illustrate that the additional revenues in the market from ESI far exceed the change in costs of holding additional fuel, illustrating the strong incentives created by ESI for oil resources to increase the quantity of fuel held during the winter. This incremental oil will help maintain system reliability during periods of system stress.

Table 11. New ESI Revenues and Change in Holding Costs, Frequent Stressed Conditions

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Dual Fuel, Combined Cycle	17	-$14	$5,452	$139	$5,577
Dual Fuel, CT	14	-$118	$5,875	$2,172	$7,929
Oil Only, CT	70	-$134	$1,784	$5,735	$7,385
Oil Only, Steam	13	-$1,257	$6,207	$583	$5,532

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

Table 12. New ESI Revenues and Change in Holding Costs, Extended Stressed Conditions

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Dual Fuel, Combined Cycle	17	-$112	$2,113	$61	$2,063
Dual Fuel, CT	14	-$124	$1,760	$1,199	$2,835
Oil Only, CT	70	-$88	$654	$2,032	$2,598
Oil Only, Steam	13	-$1,291	$2,646	$98	$1,453

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

Table 13. New ESI Revenues and Change in Holding Costs, Infrequent Stressed Condition

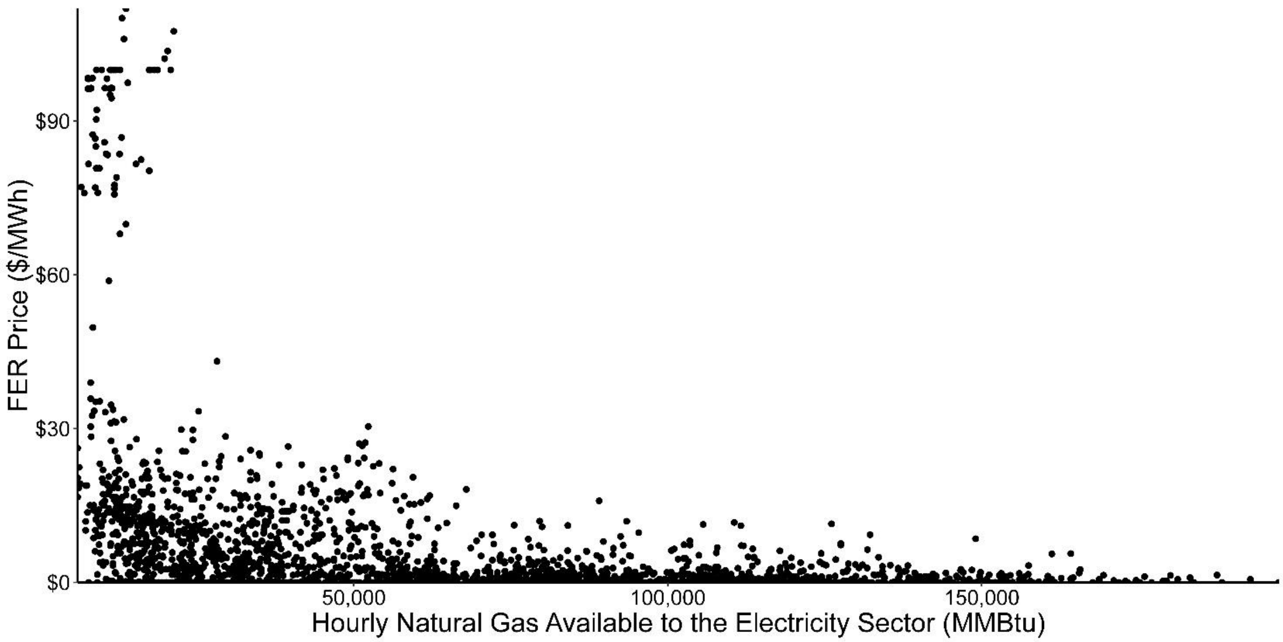
Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Dual Fuel, Combined Cycle	17	-$254	$785	$12	$543
Dual Fuel, CT	14	-$435	$150	$444	$159
Oil Only, CT	70	-$84	$7	$720	$643
Oil Only, Steam	13	-$1,315	$94	$3	-$1,218

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

Another indicator of the ESI proposal's strong incentives is the magnitude of the price signals during periods of system stress. As with any market design, prices signals for the desired service should be strongest when the need for these services is greatest. In this case, ESI is designed to provide strong price signals to resources to reward the ability to deliver energy during periods of system stress. Thus, to incent efficient improvements in reliability, these prices should be largest during periods when energy inventory is low and, to be effective, they should be large enough to offset the costs of supplying the needed service during the periods of need.

The opportunities to earn additional FER payments and supply additional DA energy options are greatest when market conditions are tight, and the resource's output might otherwise be constrained. These are also the periods when these new revenues are largest. **Figure 15** shows the FER price and the natural gas supply available to the electricity sector, a metric of system stress, for each hour in the Frequent Case. When natural gas supplies are limited, fuel oil resources will be most competitive for supplying DA energy and DA energy options. As shown in the figure, FER prices are highest in these stressed conditions. Thus, ESI's incentives are strongest when the need is greatest and resources with fuel oil inventories would most benefit from having larger inventories.

Figure 15. FER prices and Electricity Sector Natural Gas Supply, Frequent Case



The magnitude of ESI prices also needs to be sufficiently high to incent storing additional fuel. **Figure 16** provides hourly FER prices for each of the Central Cases. In this figure, prices have been sorted from lowest to highest. The figure illustrates the large number of hours in which large FER payments (e.g., above $20 per MWh) are earned in the stressed conditions cases. For resources earning FER payments, these revenues go directly to their profit margins, as these payments are in addition to the LMP.

Figure 16. FER Prices, Central Case

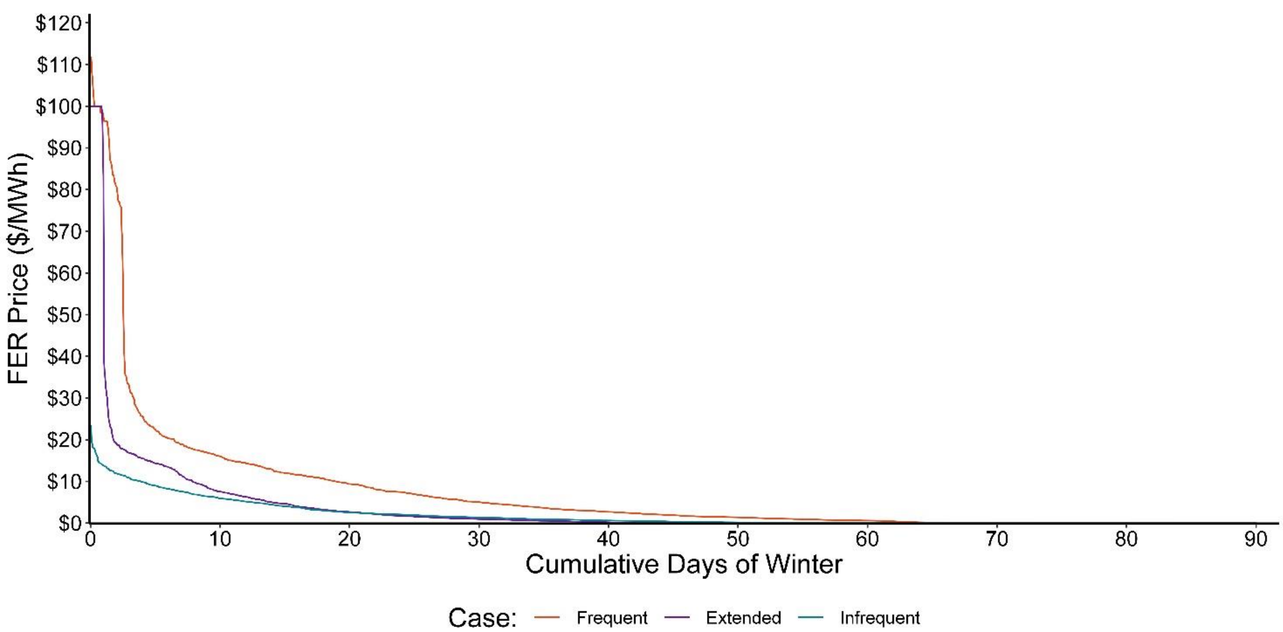


Figure 17 provides a similar hourly curve of GCR10 prices for each of the Central Cases. Consistent with the FER prices, for a fraction of hours, prices reach to high levels, above $50 per MWh. **Table 14** provides another lens on the ESI price data, providing RER prices at various statistical percentiles within the hourly sample of hours. For example, in the Frequent Case, the 96% percentile RER price is $50.75 per MWh, indicating that prices are $50.75 per MWh or greater in 4% (100% minus 96%) of the hours. As there are 2,160 hours in the winter we analyze, this implies that RER prices are above $50 per MWh in at least 86 hours. In the Extended Case, prices are above $50 per MWh in 27 hours. Thus, prices for DA energy options reach to high levels in fraction of hours that is large enough to have important incentive effects.

Figure 17. GCR10 Prices, Central Case

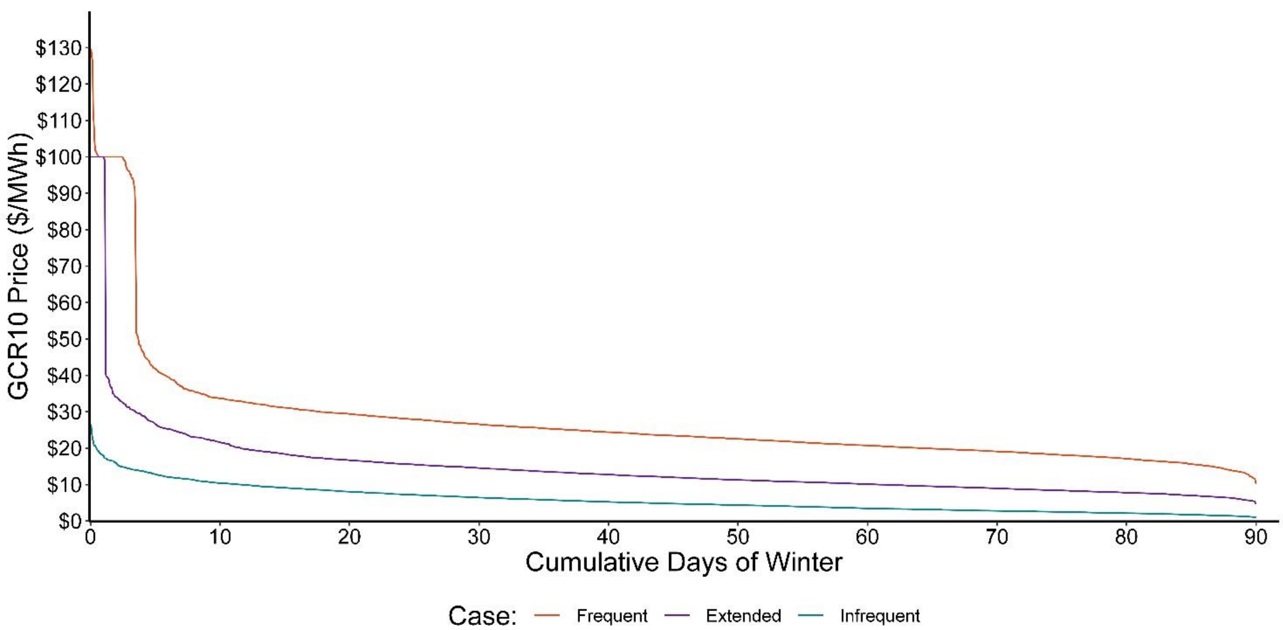


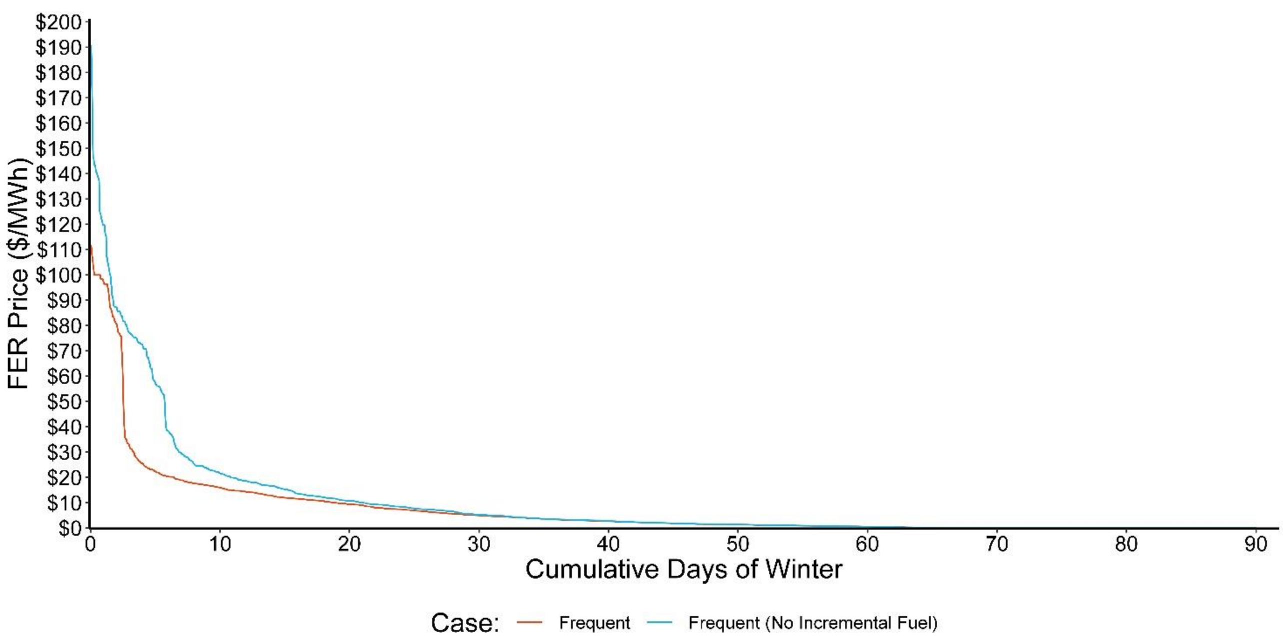
Table 14. Summary Statistics of RER Prices

	RER Percentile ($/MWh) Including Shortage Hours								
Cases	**25%**	**50%**	**75%**	**90%**	**95%**	**96%**	**97%**	**98%**	**99%**
Infrequent	$2.94	$4.76	$7.63	$10.66	$13.20	$13.92	$14.45	$16.13	$18.05
Extended	$9.26	$11.98	$16.05	$22.30	$26.99	$28.88	$30.65	$33.79	$100.00
Frequent	$19.51	$23.45	$28.63	$34.40	$43.91	$50.75	$97.54	$100.00	$100.00
All Cases	$6.88	$12.64	$21.21	$28.44	$32.90	$34.31	$37.56	$44.67	$100.00

These tables and figures illustrate that the returns to incremental inventory are large when inventory is available during these periods of system stress. For example, consider a unit that consumes residual fuel oil (RFO) with a heat rate of 9,000 Btu/kWh. If the resource does not consume the fuel during the winter, it incurs a holding cost of approximately $13 per MWh to keep the fuel in inventory until the next winter.[38] However, if the fuel is consumed, then the resource earns a return equal to the incremental market revenues net of its production costs. Under current market rules, these revenues reflect only the LMP. But, under ESI, revenues also include FER payments and the opportunity to supply DA energy options. As shown above, during periods of system stress, these payments can be large, more than offsetting the holding cost. For example, in the Frequent Case, FER payments exceed $13 per MWh in a large fraction of hours. Thus, investment in fuel inventory can allow the resource owner to reap additional returns during periods of system stress, which aligns with ESI's reliability objectives.

In these exhibits, the frequency high FER and ESI prices already reflects the incremental fuel supplies assumed under the ESI case. Thus, even after accounting for the effect of assumed incremental fuel supplies under ESI, price signals for improved reliability remain strong in a meaningful fraction of hours. Moreover, absent these fuel supplies the frequency of high prices would be even greater. For example, **Figure 18** shows the FER prices with and without the incremental fuel supplies assumed under ESI. As shown, absent the incremental fuel supplies, the frequency of high prices is substantially higher.

Figure 18. FER Prices, Central Case with and without Incremental Fuel, Frequent Case



These results demonstrate that the assumed incremental fuel inventory incented by ESI are a reasonable and plausible responses by market participants. **Figure 16** to **Figure 18** show that there are still opportunities to earn substantial returns from supplying DA energy and DA energy options during periods of system stress by increasing the holding of fuel oil. These incentives will be greatest for those resources with the greatest risk of having fuel inventories reduced to the point that it constrains supply decisions, illustrating that ESI's

38 This calculation also assumes $9.64 per MMBtu for Refined Fuel Oil, and a holding cost of 15%. See the appendix.

incentives efficiently target those opportunities to increase inventory that would provide the greatest value to system reliability relative to their incremental costs.

d) Incentives for Investment in Incremental Forward LNG Contracts

We analyze the changes in incentives for a gas-only resource to enter into a forward contract with an LNG terminal under ESI as compared to current market rules. At present, the LNG terminals have entered into various forward contracting arrangements with LDCs, some generators, and potentially other market participants. LNG terminal owners have indicated that they could expand forward contract volumes with New England market participants.

ESI would provide additional incentives for market participants to enter into additional forward contract volumes with the LNG terminals. Like the fuel oil resources analyzed in the prior section, these additional revenues potentially come through FER payments and the sale of DA energy options. **Table 15** provides our analysis of the potential incremental revenues under ESI to the holder of a forward LNG contract.[39] In our analysis, the resources chosen to hold the forward contract clear all of the energy supply supported through these contracts through day-ahead (and real-time) energy, but supply no DA energy options. This pattern of supply is a feature of the limit to the low-cost energy supplies available through the LNG contract (since we assume a contract 10 days of calls), the pattern of LMPs in the market during tight market periods (cold snaps), and the limitations to the ability of some units to supply DA energy options unless they are already supplying energy. Thus, the potential gains considered in our analysis reflect only incremental FER payments.

In the cases representing stressed market conditions, ESI would provide incremental revenues of $2,066 and $1,511 per MW in the Frequent and Extended Cases, respectively. By contrast, there are no incremental revenues in the Infrequent Case because weather conditions are so mild that gas prices are not high enough to exercise any calls on natural gas supplies under the contract.

Table 15. Forward LNG Contract, Incremental ESI Revenues from FER Payments

Severity	FER Hours	FER Price [A]	FER MWh [B]	**FER Payments ($) [C] = [A]*[B]**	**FER Payments ($/MW)**
Frequent Case	240	$8.70	146,311	$1,273,243	$2,066
Extended Case	240	$6.36	146,311	$931,241	$1,511
Infrequent Case	0	NA	0	$0	$0

The quantitative analysis captures some but not all of the potential gains from a forward LNG contract under ESI. One issue is the relatively simple (static) decision-making rules used to exercise the call options.[40] We

[39] These revenues reflect an assumed forward contract with a strike price of $10 per MMBtu, 10 calls and no take-or-pay obligation. In practice, generators and LNG terminals may enter into different contract structures. To the extent that these alternative contract structures are preferred, they may provide greater net benefits, and thus present a lower gap to contracting than the estimated gap assuming the call option contract structure.

[40] The analysis assumes a static threshold for exercising the call options ($16 per MMBtu) that is above the commodity price ($10 per MMBtu). The higher threshold for exercising the call option captures the opportunity cost of exercising one of the limited number of call options. It ensures that the owner does not exercise the call to earn a small return, thus precluding a potential future returns of higher magnitude. This threshold was calculated using quantitative analysis of historical New England market conditions.

assume that call options are not exercised unless natural gas prices exceed a fixed threshold, based on analysis of historical data. With more complex decision-making rules for determining when to exercise call options, the contract could potentially earn higher returns than those presented in **Table 15**. For example, the contract holder earns no returns in the Infrequent Case, although relaxing the threshold prices for exercising the call options could provide the holder with some gains from the contract.

A second issue it that our analysis does not capture the gains from reduction in financial risk under certain market conditions. In particular, while the analysis captures the gains from reductions in risk when natural gas prices are relatively high (e.g., exceeding the LNG price), it does not account for risk benefits when prices are relatively low (e.g., less than the LNG price). For example, a forward LNG contract would cover intra-day fuel price risk for a gas-only facility awarded a DA energy option on a day when natural gas prices are relatively low. Without the forward LNG contract, the unit selling the option would face the risk that real-time prices would increase dramatically the next day, without having access to fuel at a price consistent with the strike price. A forward LNG contract would help mitigate this risk, a benefit that is not captured quantitatively.

Under current market rules, there may be a gap between prices a generator and LNG terminal are willing to accept for a forward LNG contract. Prior work estimated this gap to be $2,705 per MW in the context of establishing a compensation rate for the Interim Program.[41] This analysis did not attempt to account for the heterogeneity in this gap among market participants. In practice, the magnitude of this gap likely varies across market participants, with some higher and others lower than this estimate. For example, some market participants currently enter into forward LNG contracts, implying no gap.

Incremental ESI revenues may close whatever gap there is between additional generators and the region's LNG terminals to reaching agreement. In the Extended and Frequent Cases, incremental ESI revenues are of the same order of magnitude as the amount that was estimated to be necessary to incent LNG contracting in the context of the Interim Program. That is, the incremental revenues are $1,511 per MW in the Extended Case and $2,066 per MW in the Frequent Case, as compared to an estimated gap of $2,705 per MW. Thus, these incremental revenue streams due to ESI are the same order of magnitude as an estimate of the gap for resources to enter into incremental contracts, suggesting that ESI would potentially incent some resources toward entering into such contracts that would otherwise not do so.

2. Supply of Energy and DA Energy Options

The ESI proposal is expected to result in multiple changes to day-ahead and real-time energy supply, including changes in the supply of energy (clearing in the day-ahead market), shifts in the composition of resources supplying energy in both day-ahead and real-time markets, and a new supply of DA energy options.

Historically, the supply of physical energy clearing in the day-ahead markets has typically been less than the ISO load forecast. **Table 16** compares the quantity of DA physical cleared energy to the ISO load forecast in our CMR Case, which is based on historical cleared DA energy and load forecasts. When the day-ahead market clears physical energy supplies below the ISO load forecast, resources in the market implicitly supply

[41] Analysis performed in the context of analysis performed for the interim inventories energy program. *See* Testimony of Todd Schatzki, Federal Energy Regulatory Commission, Docket No. ER19-1428-000.

load with an option to supply additional energy needed to meet load in real-time. This option is exercised through a variety of means, including the supplemental reliability commitment implemented by ISO-NE after the DA market has cleared. Supplemental commitments may cause additional resources to be committed if the reliability analysis determines that commitments from the resources clearing in the DA market are not sufficient to meet ISO-NE's load forecast given the operational capabilities of cleared resources (and other factors). Even if not committing additional units, reliability may be maintained through the ramp capability of units that clear a portion of their operating capacity in the DA market. These services are presently uncompensated, and as a result, the financial incentives for such resources to take the necessary actions to be available if called may not be consistent with the reliability services they provide.

Table 16. Percent of Hours with Cleared Supply Less than Forecast Load, CMR Case
(Short)

	Cleared DA Energy Supply < ISO Forecast Load	
CMR Case	**Share of Hours (%)**	**Average Difference (MW)**
Frequent Case	92%	519
Extended Case	64%	334
Infrequent Case	81%	383

Note: The load forecast depicted in the table is the forecast available prior to clearing the DAM, at around 9:30am on OD-1.

An important element of the ESI design is the increase in DA cleared energy caused by co-optimization of the DA energy and EIR requirement, and the expected increase in day-ahead bid-in demand. Section III.B.5 described these adjustments in greater detail. In short, with ESI, costs are minimized by substituting DA energy for EIR, which reduces the gap between cleared DA energy and the forecast load. DA bid-in demand increases to eliminate arbitrage opportunities between the day-ahead and real-time markets, which further reduces the gap between cleared DA energy and the forecast load.

Table 17 shows the changes in DA energy by resource type between CMR and ESI. Under CMR, the total energy clearing in the DA market ranges from 31.0 to 31.5 TWh across Cases (column [A]). By contrast, under ESI, total cleared DA energy ranges from 31.6 to 32.2 TWh (column [B]), representing an increase of 0.4 to 1.0 TWh of DA energy supply. Thus, ESI leads to increases of 1.4% to 3.3% in DA energy compared to current market rules.

Table 17. Changes in Cleared DA Energy
CMR vs ESI, Central Cases

	CMR	ESI		Difference	Real-Time Comparison	
Case	Day-Ahead Energy [A]	Day-Ahead Energy [B]	Cleared EIR [C]	Day-Ahead Energy [D] = [B] - [A]	Real-Time Demand	Energy + EIR [E] = [B] + [C]
Frequent Case	31,188,025	32,215,469	6,604	1,027,443	32,155,711	32,222,073
Extended Case	31,503,187	31,943,398	25,172	440,211	31,840,458	31,968,570
Infrequent Case	31,047,336	31,634,655	83,245	587,318	31,525,206	31,717,899

The increases in DA energy occur during hours when the energy supply clearing in the DA market would be less than the ISO load forecast under current market rules. However, the substitution of DA energy for EIR does not completely eliminate the gap between cleared DA energy and the ISO load forecast.[42] For each Case, column [C] shows the quantity of cleared EIR, which ranges from 6.6 to 83.2 GWh. Thus, the EIR quantity is small compared to the difference in DA energy under CMR and ESI, indicating that ESI may be expected to reduce most of the gap between DA cleared energy supply and the ISO load forecast that exists under the current market rules.

Table 18 to **Table 20** shows the impact of ESI on the products supplied in the DA markets across resource types. Compared to current market rules, ESI leads to a shift in the supply of DA energy across resource types. Because of the increase in total DA energy caused by ESI, most resources increase the supply of DA energy, with the largest increases for combined cycle units (dual-fuel and gas-only), oil-only steam units and dual-fuel combustion turbines. DA energy options are supplied by a mix of resources, including (in order of quantity supplied) pumped storage, combustion turbines (all fuel types), hydro power and combined cycle units (dual fuel and gas-only).

The value of the opportunity to supply DA energy options varies across resource types. At one extreme, oil-only non-steam (CT) units supply about 10 times the amount of DA energy options compared to DA energy. At the other extreme, combined cycle units (gas-only and dual fuel) supply about 10 times the amount of DA energy relative to DA energy options. Thus, the cost-effective allocation of DA energy and DA energy options reflects the cost of supplying energy – with the lowest marginal cost resources generally selected – but also the cost of supplying DA energy options, given the costs and risks associated with selling an option.

There is some substitution between DA energy and DA energy options for some resource types. For example, although total DA energy increases, supply from oil-only combustion turbines decreases. However, this decrease is offset by a large supply of DA energy options provided by these resources. For example, in the Frequent Case, DA energy decreases by 29,182 MWh (more than a 10% decrease), while 2.0 TWh of DA energy option are awarded.

[42] In these hours, clearing additional DA energy would lead to larger economics losses – the difference in price between demand bids and supply offers – than savings in reduced purchase of DA energy options.

Table 18. Energy and DA Energy Options by Resource Type
CMR vs ESI, Central Case, Frequent Stressed Conditions (MWh)

Resource Type	Capacity SCC (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	285	18,559	18,810	0	251
Battery Storage	458	41,206	41,206	0	0
Biomass/Refuse	849	1,601,428	1,601,638	0	211
Coal	535	957,230	964,935	10,540	7,705
Dual Fuel - CC	6,392	5,887,192	6,225,924	414,403	338,733
Dual Fuel - CT	1,435	697,219	739,743	1,297,907	42,525
Fuel Cell	21	35,109	35,123	0	15
Gas - CC	7,583	3,131,703	3,467,244	405,473	335,541
Gas - CT	404	669	704	280,643	35
Gas with LNG under ESI	616	1,020,701	1,076,091	67,815	55,390
Hydro	1,987	1,251,996	1,251,996	790,887	0
Imports	2,850	6,096,019	6,099,641	0	3,622
Nuclear	3,344	7,184,403	7,184,403	0	0
Offshore Wind	800	879,483	879,483	0	0
Oil Only - Steam	3,792	1,290,766	1,560,537	217,653	269,771
Oil Only - CT	2,511	194,309	165,127	2,003,399	(29,182)
Pumped Storage	1,778	616,108	616,108	2,251,837	0
Solar	1,671	152,197	152,197	0	0
Wind	1,401	992,964	992,964	0	0

Note: (1) DA energy for battery storage and pumped storage reflect (on-peak) discharged supply, and is not net of (off-peak) charging withdrawals.
(2) Oil Only - CT is largely combustion turbine units, but also include internal combustion engines.

Table 19. Energy and DA Energy Options by Resource Type
CMR vs ESI, Central Case, Extended Stressed Conditions (MWh)

Resource Type	Capacity SCC (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	285	23,846	11,850	0	(11,996)
Battery Storage	458	41,206	41,206	0	0
Biomass/Refuse	849	1,581,343	1,577,716	0	(3,627)
Coal	535	646,721	652,128	9,048	5,406
Dual Fuel - CC	6,392	5,416,572	5,618,953	397,252	202,381
Dual Fuel - CT	1,435	470,553	494,509	1,428,271	23,956
Fuel Cell	21	23,202	23,316	0	115
Gas - CC	7,583	4,729,551	4,933,753	264,301	204,202
Gas - CT	404	0	0	304,397	0
Gas with LNG under ESI	616	1,242,134	1,287,505	34	45,372
Hydro	1,987	1,526,266	1,526,266	1,123,614	0
Imports	2,850	5,929,432	5,931,763	0	2,331
Nuclear	3,344	7,184,403	7,184,403	0	0
Offshore Wind	800	879,483	879,483	0	0
Oil Only - Steam	3,792	619,222	641,855	35,773	22,634
Oil Only - CT	2,511	116,800	64,788	1,148,060	(52,012)
Pumped Storage	1,778	616,108	616,108	3,080,047	0
Solar	1,671	245,603	245,603	0	0
Wind	1,401	1,083,132	1,083,132	0	0

Note: See note for **Table 18**.

Table 20. Energy and DA Energy Options by Resource Type
CMR vs ESI, Central Case, Infrequent Stressed Conditions (MWh)

Resource Type	Capacity SCC (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	285	4,246	4,380	0	134
Battery Storage	458	41,206	41,206	0	0
Biomass/Refuse	849	1,559,242	1,559,753	0	510
Coal	535	549,273	558,894	15,725	9,621
Dual Fuel - CC	6,392	5,170,503	5,443,353	357,917	272,850
Dual Fuel - CT	1,435	362,534	362,669	1,526,744	135
Fuel Cell	21	12,645	13,162	0	517
Gas - CC	7,583	5,543,212	5,830,502	291,525	287,290
Gas - CT	404	74	74	393,496	0
Gas with LNG under ESI	616	1,316,801	1,316,801	0	0
Hydro	1,987	1,421,185	1,421,185	1,137,865	0
Imports	2,850	5,850,967	5,856,778	0	5,811
Nuclear	3,344	7,184,403	7,184,403	0	0
Offshore Wind	800	931,752	931,752	0	0
Oil Only - Steam	3,792	51,739	61,149	2,058	9,410
Oil Only - CT	2,511	2,553	3,556	1,324,243	1,003
Pumped Storage	1,778	616,108	616,108	2,809,637	0
Solar	1,671	289,960	289,960	0	0
Wind	1,401	1,017,230	1,017,230	0	0

Note: See note for **Table 18**.

The mix of energy supply varies across time with changes in market conditions, including load levels, natural gas supply available to the electricity sector (given weather-related variation in LDC natural gas demand), and the duration of periods of tight natural gas supplies, which may cause a drawdown in energy inventories. **Figure 19** illustrates the hourly cleared supply of DA energy by technology type. The figure illustrates the shifts in supply that occur during periods of tight natural gas supplies, where awards to generators relying on dual fuel oil generation (purple) and oil-only generation (black) are generally increasing compared periods with less stressed market conditions.

Table 12 shows the mix of resources that make up differences in DA energy between CMR and ESI in each hour. In each hour, the difference in DA energy supply reflects increases by some resources (shown by amounts greater than zero) and decreases by others (shown by amounts less than zero).

Figure 19. Hourly Cleared DA Energy by Resource Type

ESI, Central Case, Frequent Stressed Conditions (MWh)

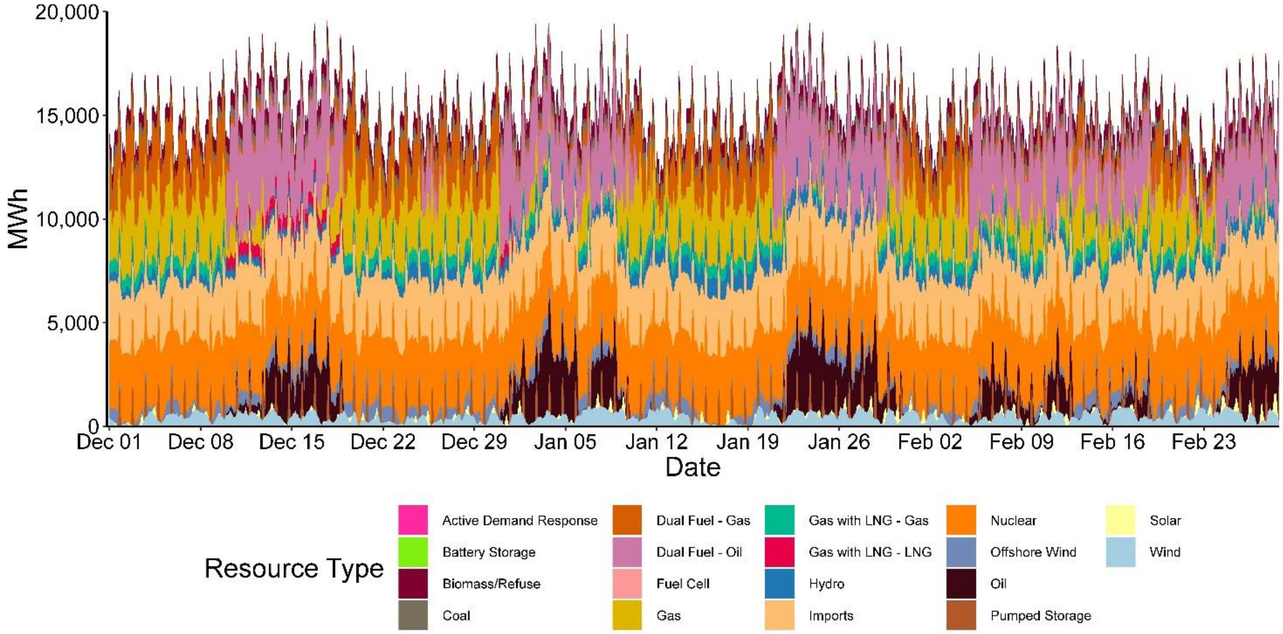
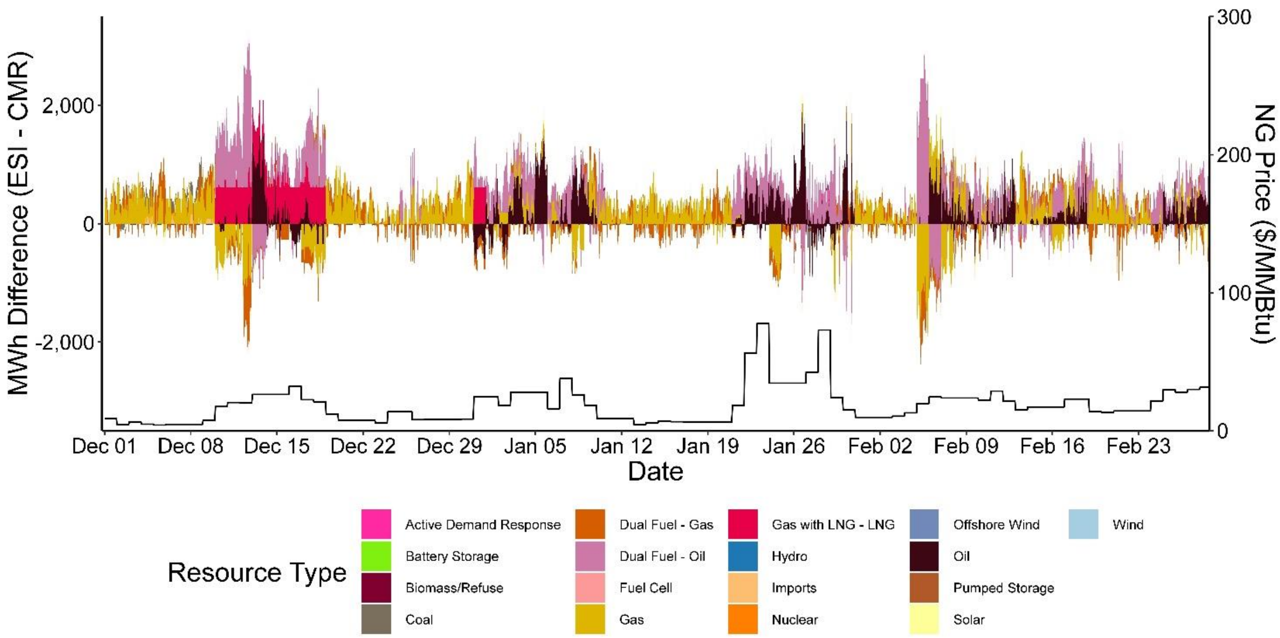


Figure 20. Difference in Hourly Cleared DA Energy by Resource Type
CMR vs ESI, Central Case, Frequent Stressed Conditions



3. *Production Costs*

The ESI proposal would be expected to change the total production costs of incurred to meet real-time loads through the additional energy inventory incented by ESI and the shifts in energy supply through changes in energy inventory use. These additional fuel supplies would be expected as a result of new incentives from ESI for resources to increase energy inventories and otherwise increase the ability of resources to deliver energy supply in real-time (e.g., through general improvements in operational performance). With larger energy inventories (and better resource performance), the cost of meeting real-time loads would be reduced, particularly during periods of tight fuel supply when the market would otherwise require that load be met through more costly generation resources.

Table 21 shows the estimated change in total production costs. The estimate of total production costs includes the marginal cost of production, including fuel and variable costs.[43] For example, in the Frequent Case, total model production costs are $1.42 billion under CMR and $1.37 billion under ESI, resulting in a $40.7 million reduction in model production costs. Under ESI, the quantity of energy held in inventory at the end of the winter season is greater than under CMR. The estimated change in cost of holding this fuel until the beginning of the next winter season is $5.3 million. Netting these holding costs from the $40.7 million reduction in production costs of supplying energy to load results in a change in total production costs of $35.5 million. Results are similar in the Extended Case, with total production costs reduced by an estimated $19.3 million, reflecting a reduction in model production costs of $25.0 million and an increase in holding costs of $5.7 million.

In contrast to the Frequent and Extended Cases, costs increase in the Infrequent Case by $7.5 million, reflecting a $0.9 million reduction in total model production costs and an increase in energy inventory holding costs of $8.5 million. Thus, these results suggest that ESI may not lower production costs under all market conditions.

These results show that ESI operates in a manner similar to insurance with respect to total economic costs. Similar to insurance, ESI would be expected to increase energy inventory, providing increased economic "protection" that lowers costs during periods of tight market conditions. However, similar to insurance, the cost of this protection may not always produce benefits that outweigh the costs, especially during "mild" conditions.

Table 21. Difference in Production Costs
CMR vs ESI

Case	Total Model Production Costs [1] ($ Million)			Incremental Energy Inventory Costs with ESI [2] ($ Million)	Change in Total Production Costs ($ Million)
	CMR	ESI	Change		
Frequent Case	$1,415.1	$1,374.4	($40.7)	$5.3	($35.5)
Extended Case	$939.5	$914.5	($25.0)	$5.7	($19.3)
Infrequent Case	$657.2	$656.3	($0.9)	$8.5	$7.5

Notes:
[1] Production costs only do not include opportunity costs.
[2] Incremental energy inventory costs include LNG and oil holding costs for incremental fuel at the end of the winter.

[43] Estimated production costs exclude costs associated with nuclear, pumped storage, hydropower, wind power and solar.

4. *Emissions*

Shifts in the mix of energy supply caused by ESI would lead to corresponding changes in total emissions given differences in the emission rates across resources in the fleet. **Table 22** shows the change in emissions between CMR and ESI for each of the Central Cases. Estimates of changes in total emissions reflect resource-specific emission rates and shifts in RT supply from particular resources. Emissions increase in some cases, and decrease in others. For example, carbon dioxide and sulfur dioxide emissions decrease in two of three cases. By contrast, oxides of nitrogen emissions increase in all three cases.

Table 22. Difference in Emissions (lbs)
CMR vs ESI

Case	CO_2		SO_2		NOx	
Frequent Case	124,298,774	0.63%	211,494	1.45%	1,372,155	4.44%
Extended Case	(53,987,006)	-0.31%	(109,636)	-1.26%	197,090	1.10%
Infrequent Case	(5,232,664)	-0.03%	(5,551)	-0.09%	19,985	0.17%

5. *Customer Payments*

Total change in customer payments due to the ESI proposal will reflect a combination of factors:

- First, total LMP payments through DA and RT markets will shift due to a combination of factors. Several factors put down pressure on LMPs, including the increase supply of energy in inventory due to ESI's incentives to secure increased energy inventory, and the increase in supply of energy clearing the day-ahead market given the substitution of DA energy for EIR (which *lowers* LMPs because DA energy generally clears at bid-in demand). On the other hand, the shift in energy mix due to various intra-hour and inter-hour substitutions within the market could increase LMPs.
- Second, resources supplying DA energy will receive FER payments as compensation for contributions to meeting the Forecast Energy Requirement.
- Third, new payments will be made in the DA market for DA energy options, and when RT LMPs are above the strike prices, load will be credited for the settlement of these options. This real-time settlement will partially offset the DA payments for the options, but to the extent that participants include a risk component in their offer price, this closeout settlement is unlikely to fully offset the DA payment, on average.

Table 23 summarizes the net impact of these three components on total customer payments. In the Infrequent Case, payments increase by $35 million over the 3-month winter (a 2.0% increase), reflecting an increase in payments to energy of $20 million (reflecting a $41 million reduction associated with changes in LMPs and $61 million increase payments due to FER payments) and net payments of $15 million for DA energy options. Total payments both increase and decrease in the stressed conditions cases. In the Frequent Case, payments increase by $132 million (a 3.2% increase), reflecting a decrease in LMP payments of $183 million, FER payments of $250 million and net DA energy option payments of $66 million. In the Extended Case, however, payments decrease by $69 million (a 2.5 percent decrease), reflecting a decrease in LMP payments of $214 million, FER payments of $113 million and net DA energy option payments of $32 million.

Table 23. Total Payments by Case ($ Million)

Product / Payment		Frequent Case CMR	Frequent Case ESI	Frequent Case Difference		Extended Case CMR	Extended Case ESI	Extended Case Difference		Infrequent Case CMR	Infrequent Case ESI	Infrequent Case Difference	
Energy and RT Operating Reserves	[A]	$4,101	$3,917	-$183	-4.5%	$2,730	$2,516	-$214	-7.8%	$1,749	$1,707	-$41	-2.4%
DA Energy Option													
DA Option Payment			$207				$113				$45		
EIR			$0				$1				$1		
RER			$67				$37				$15		
GCR10			$93				$50				$20		
GCR30			$47				$25				$10		
RT Option Settlement			-$142				-$81				-$31		
Net DA Ancillary	[B]		$66				$32				$15		
FER Payments	[C]		$250				$113				$61		
Total Payments	[A+B+C]	$4,101	$4,233	$132	3.2%	$2,730	$2,661	-$69	-2.5%	$1,749	$1,783	$35	2.0%

Payments for the ESI products reflect both upfront payments for the DA energy options and settlement of the options, which provides offsetting compensation to load. **Figure 21** to **Figure 23** shows these net effects at the hourly level to illustrate the variability in net impacts. **Figure 21** shows the upfront payments for the DA energy options, **Figure 22** adds the settlement of the options, represented as an offset to the cost, and **Figure 23** adds the net payment on each day.

Figure 21. Hourly DA Energy Option Payments

All ESI Products, Central Case, Frequent Stressed Conditions, Jan 8 to Jan 22 ($ Thousands)

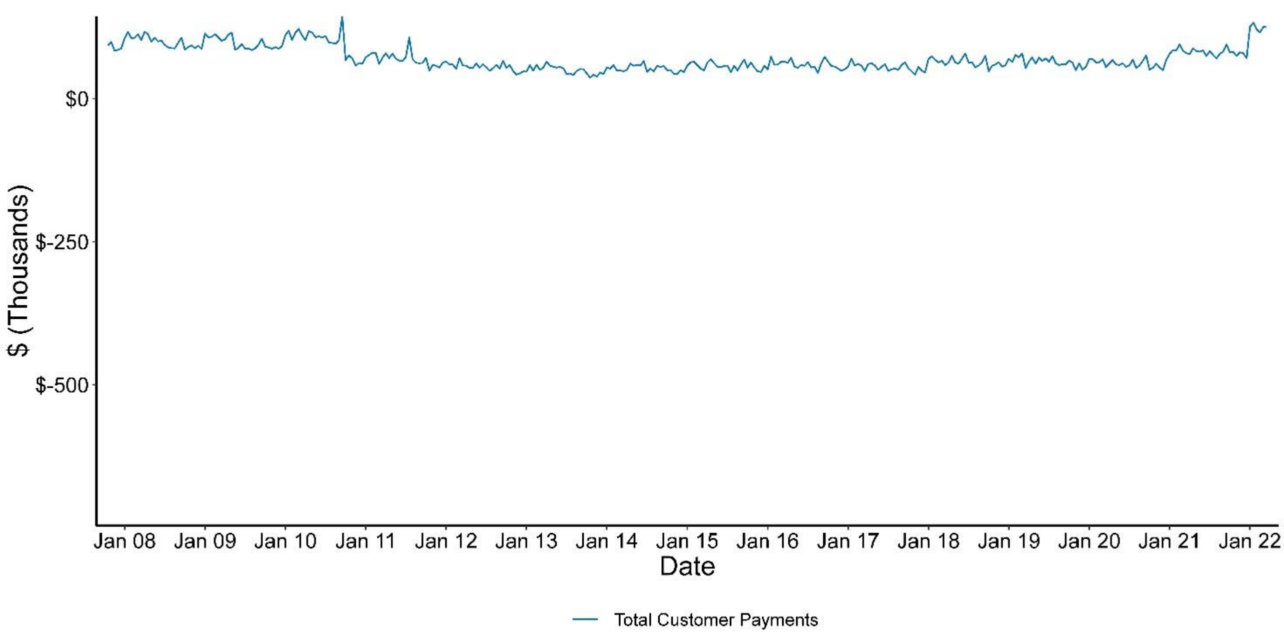


Figure 22. Hourly DA Energy Option Payments and RT Option Settlement
All ESI Products, Central Case, Frequent Stressed Conditions, Jan 8 to Jan 22 ($ Thousands)

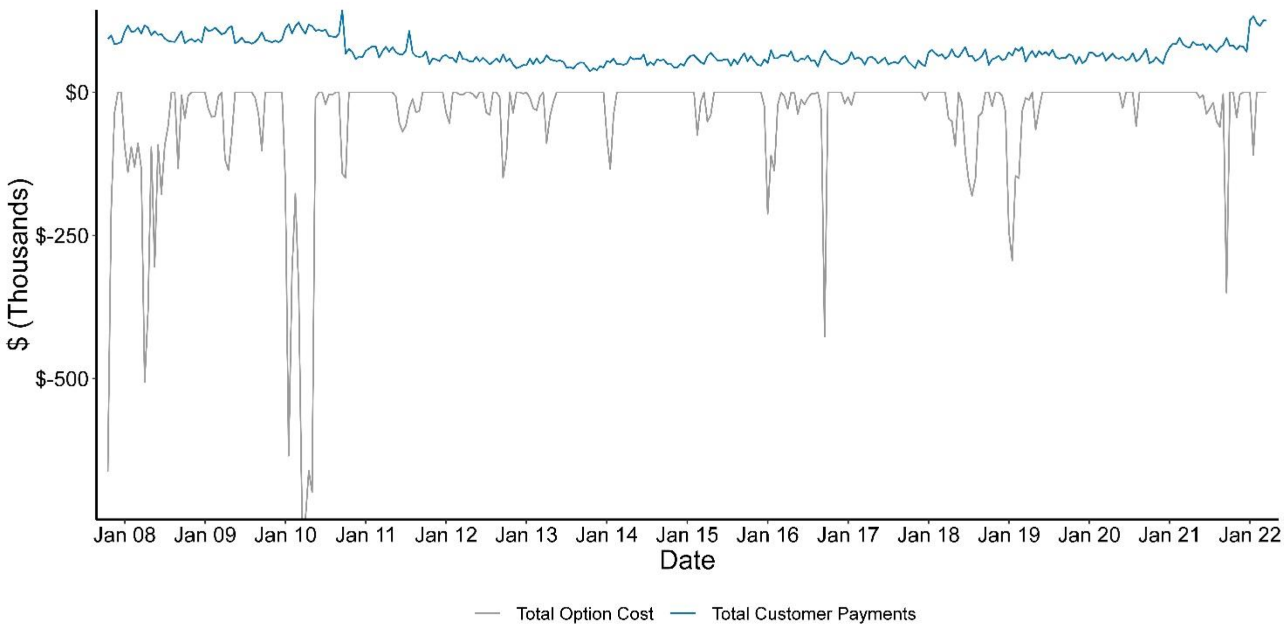
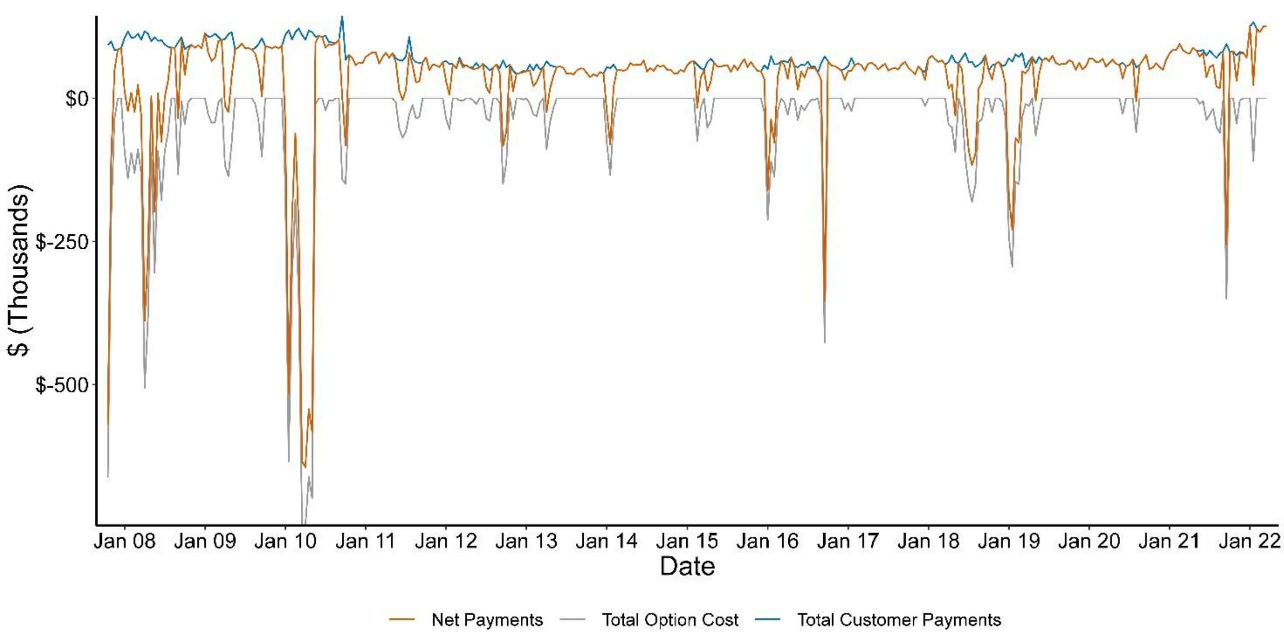


Figure 23. Hourly DA Energy Option Payments, RT Option Settlement and Net Payments
All ESI Products, Central Case, Frequent Stressed Conditions, Jan 8 to Jan 22 ($ Thousands)



6. Resource Net Revenues

The impact of ESI on the net revenues earned by resources participating in the New England energy markets depends on a combination of factors. In aggregate, changes in payments by load will lead to corresponding changes in revenues to generators. Thus, in Cases when payments to load are expected to increase, this would be expected to lead to a corresponding increase in revenues to resource owners. Production costs may change as well, sometimes increasing and sometimes decreasing.

Table 24 to **Table 26** provide the average net revenues by resource type for the Frequent, Extended and Infrequent Cases, respectively. Unlike the analysis of incentives for energy inventory, the change in net revenues accounts not only for the additional FER payments and DA energy option net revenues, but also accounts for reductions in LMPs caused by the larger energy inventories. With a few exceptions, net revenues increase in Cases when payments by load are greater (i.e., the Frequent and Infrequent Cases), and net revenues decrease in Cases when payments by load are lower (i.e., the Extended Case). However, the magnitude of these changes varies across resources. These differences depend on a variety of factors, including resource-specific operational characteristics, such as plant operating efficiency, fuel costs and fuel inventory.

Table 24. Average Net Revenues by Resource Type, Frequent Case ($ per MW)

	Net Revenue ($/MW)		
Resource Type:	CMR [A]	ESI [B]	Change [C] = [B] - [A]
Dual Fuel - CC	$38,260	$42,210	$3,950
Dual Fuel - CT	$19,548	$30,244	$10,696
Gas Only - CC	$2,231	$3,273	$1,042
Gas Only - CT	$188	$6,107	$5,919
Gas with LNG under ESI	$13,244	$17,416	$4,172
Oil Only - Steam	$10,174	$14,839	$4,665
Oil Only - CT	$2,435	$8,664	$6,228
Coal	$161,951	$165,483	$3,532
Biomass/Refuse	$229,680	$233,026	$3,346
Fuel Cell	$144,742	$147,890	$3,148
Hydro	$95,745	$100,113	$4,368
Nuclear	$268,661	$272,340	$3,679
Solar	$12,222	$12,239	$17
Wind	$94,529	$95,750	$1,221
Offshore Wind	$138,457	$139,966	$1,509

Table 25. Average Net Revenues by Resource Type, Extended Case ($ per MW)

	Net Revenue ($/MW)		
Resource Type:	CMR [A]	ESI [B]	Change [C] = [B] - [A]
Dual Fuel - CC	$20,343	$18,298	($2,046)
Dual Fuel - CT	$13,555	$17,046	$3,491
Gas Only - CC	$6,257	$6,750	$494
Gas Only - CT	$0	$2,813	$2,813
Gas with LNG under ESI	$27,299	$26,965	($334)
Oil Only - Steam	$9,748	$5,283	($4,465)
Oil Only - CT	$3,964	$2,360	($1,604)
Coal	$87,783	$82,474	($5,309)
Biomass/Refuse	$148,791	$143,160	($5,632)
Fuel Cell	$76,588	$71,216	($5,373)
Hydro	$66,814	$67,193	$380
Nuclear	$175,308	$169,440	($5,869)
Solar	$9,944	$9,638	($307)
Wind	$68,604	$64,961	($3,644)
Offshore Wind	$93,357	$89,652	($3,705)

Table 26. Average Net Revenues by Resource Type, Infrequent Case ($ per MW)

	Net Revenue ($/MW)		
Resource Type:	CMR [A]	ESI [B]	Change [C] = [B] - [A]
Dual Fuel - CC	$6,594	$7,102	$508
Dual Fuel - CT	$6,070	$7,697	$1,627
Gas Only - CC	$7,702	$8,355	$653
Gas Only - CT	$21	$1,573	$1,552
Gas with LNG under ESI	$27,668	$7,348	($20,320)
Oil Only - Steam	$310	($973)	($1,283)
Oil Only - CT	$1	$752	$751
Coal	$34,234	$35,184	$950
Biomass/Refuse	$96,287	$97,453	$1,165
Fuel Cell	$27,541	$28,023	$482
Hydro	$39,673	$41,168	$1,495
Nuclear	$115,752	$117,111	$1,359
Solar	$7,707	$7,761	$54
Wind	$38,893	$39,309	$415
Offshore Wind	$60,976	$61,702	$726

7. Operational Impacts and Reliability

The proposed ESI market rules are expected to improve system reliability by procuring day-ahead services that ensure the system has energy supplies available to meet real-time operational needs. As describe above, each of the ESI products is designed to ensure that energy supplies are available to fill potential gaps in energy supplies to ensure that forecast loads can be met (EIR), operating reserves have sufficient energy supplies (GCR), and energy supplies are available to maintain reliability under extended, large contingencies (RER). Procuring these services will create incentives for resources to take actions along short-term and long-term horizons to improve their ability to provide real-time energy supplies.

As noted previously, our production cost model is not designed to provide a thorough or complete analysis of the impact of ESI on potential reliability outcomes. Such impacts are typically performed through other modeling techniques and may reflect different assumptions about a variety of factors that would impact reliability and security outcomes. The model does not consider a complex set of contingency events, does not account for transmission topology, and does not consider plant commitment, dispatch and other intertemporal limits to plant operations (e.g., minimum run times and minimum down times). Due to the combined impact of these factors, we would expect our model to understate potential reliability risks associated with any market simulation, and thereby underestimate potential reliability benefits of the ESI proposal.

Nonetheless, we analyze multiple metrics that can provide information consistent with reliability improvements. These metrics include traditional reliability metrics associated with resource availability. But, they also include a broader set of metrics related to fuel use and fuel inventory as these are related to ESI's objectives of securing energy supplies. In particular, we evaluate:

- ***Operating reserve shortages***. Hours of 10- or 30-minute operating reserve shortage.
- ***Natural gas consumption when natural supply is tight***. Change in natural gas consumption during periods when the natural gas supply is tight, as reflected by high prices (greater than $16 per MMBtu). This metric provides information on the extent to which ESI relaxes pressure on fuel supply systems during stressed conditions. This quantity is estimated net of natural gas supply from forward LNG contracts.

Minimum and average daily quantity of deliverable energy from oil-fired units. The quantity of energy (MWh) available from oil-only and dual-fuel resources given actual fuel inventory is calculated for each day. These metrics provide information on the ability of oil-fired resources to provide energy and support reliable system operations across the winter. **Figure 24** to

- **Figure 26** show the daily level of these metrics for the Frequent, Extended and Infrequent Cases, respectively. We calculate the minimum and average quantity of daily energy available over the course of the entire winter.
- **Maximum 3-day drop in energy inventory.** The largest drop in energy inventory during a 3-day period over the course of the winter. This metrics provides information on how aggressively fuel inventories are being drawn down in response to stressed market conditions. In the past, rapid draw down of energy inventories have caused reliability concerns for the region.

Figure 24. Maximum Daily Potential Generation from Oil-fired Resources
CMR vs ESI, Central Case, Frequent Case (MWh)

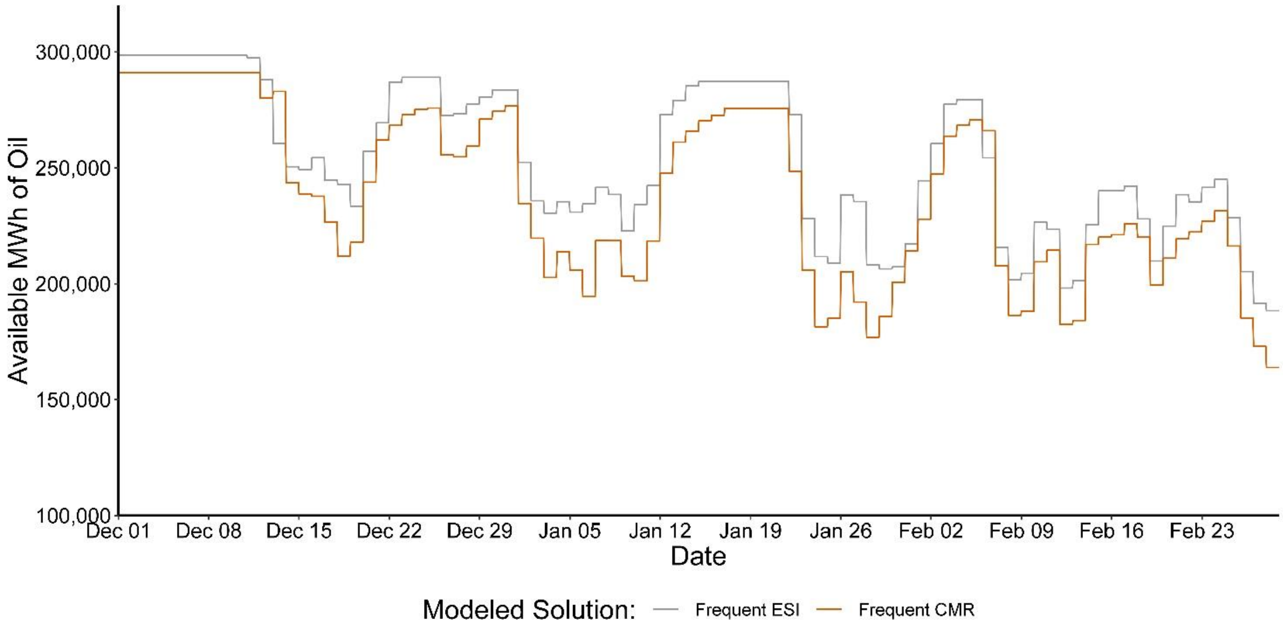


Figure 25. Maximum Daily Potential Generation from Oil-fired Resources
CMR vs ESI, Central Case, Extended Case (MWh)

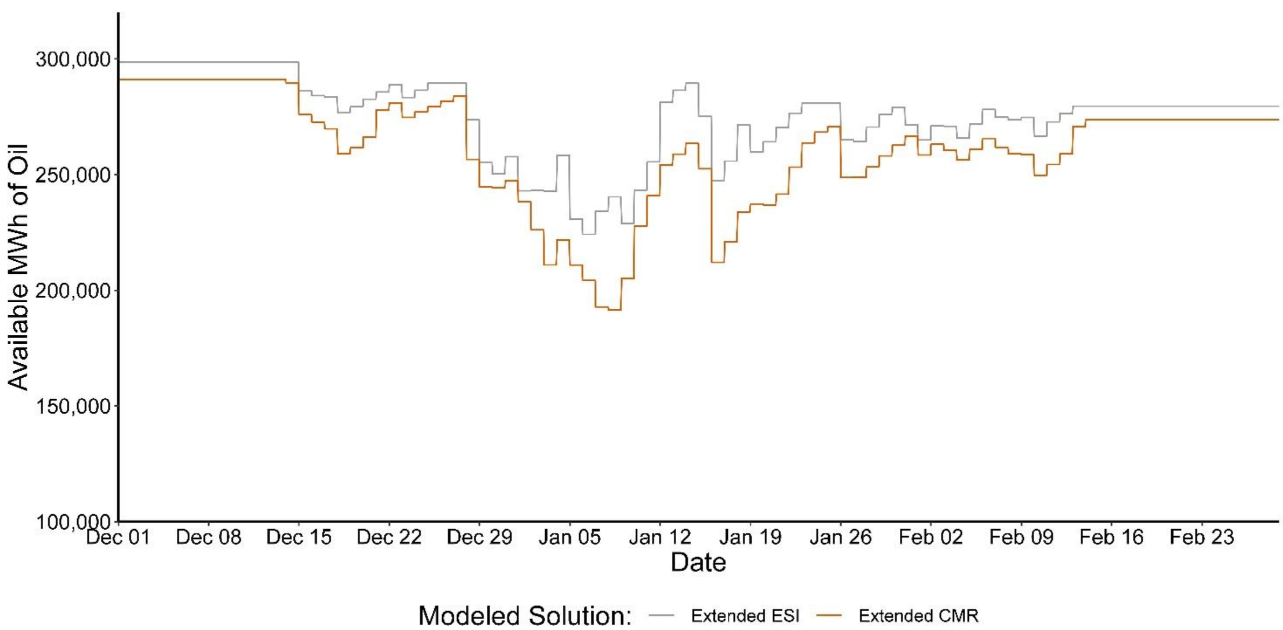


Figure 26. Maximum Daily Potential Generation from Oil-fired Resources

CMR vs ESI, Central Case, Infrequent Case (MWh)

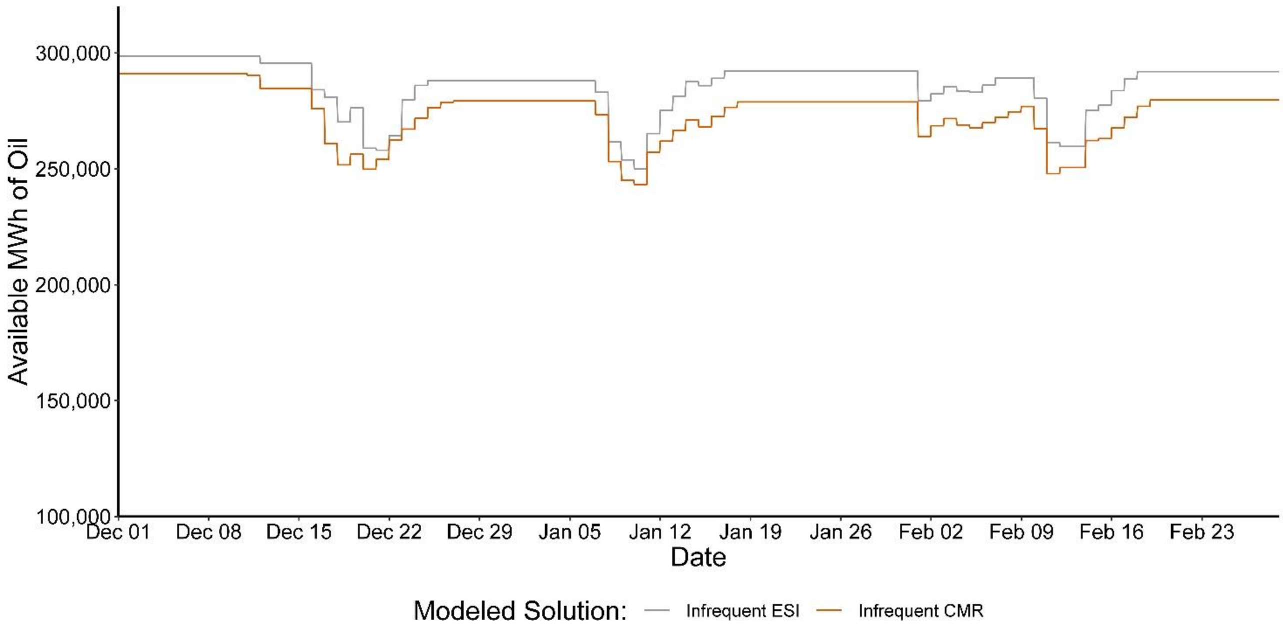


Table 27 provides the *change* in reliability metrics with ESI compared to CMR Cases. In general, reliability metrics indicate that there is less stress on physical energy systems and increased availability of energy inventory under ESI as compared to CMR. These results are consistent with improvements in reliability under ESI as compared to current market rules. For example, under ESI, natural gas consumption during stressed periods (with high natural gas prices) is reduced by 2.9 million MMBtu and 0.9 million MMBtu in the Frequent and Extended Cases, respectively. Similarly, the minimum and average quantity of oil inventory increases with ESI as compared to CMR across all Cases, with average daily energy available ranging from 11.7 to 15.2 GWh. For the particular deterministic scenarios analyzed in the Central Case, there are no operating reserve shortages in either the CMR or ESI cases, although Scenarios considering supply contingencies do find some operating reserve shortages. However, as discussed above, our analysis is not designed to provide a thorough or complete analysis of system reliability, and thus we caution drawing inferences about the current or present reliability of the system from our results.

In addition, operational metrics tend to show greater benefit under stressed market conditions (Frequent and Extended Cases) as compared to unstressed market conditions (Infrequent Case). For example, while natural gas consumption reduces in the Cases reflecting stressed market conditions, there is no change in consumption during unstressed market conditions (Infrequent Case). The same pattern is observed for the supply of energy inventory (MWh) from oil-fired resources.

Table 27. Change in Reliability Metric with ESI compared to CMR Cases

Case	Operating Reserve Shortages (Hours)	Natural Gas Used in Generation When NG Economically Binding (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline
Frequent Case	0	(2,897,177)	24,512	15,204	(16,413)
Extended Case	0	(943,020)	32,663	14,022	(7,527)
Infrequent Case	0	0	6,753	11,656	(77)

B. Non-Winter Cases

To assess the impacts of ESI in non-winter months, we evaluate two non-winter Cases, a Moderate Case, reflecting moderate or typical market conditions, and a Severe Case, reflecting severe conditions with higher energy loads. Below, we summarize the estimated impacts on prices and compensation to energy supply, energy supply, customer payments and resource net revenues.

In our quantitative analysis of non-winter month impacts, we assume that market participant decisions related to resource operations are the same in both the CMR and ESI cases. Thus, while we expect that ESI's incentives may have some effect on the decisions market participants make that affect their resources ability to reliably deliver energy supplies in real-time, such effects would be difficult to quantity, particularly for the market conditions assumed in our Central Case.

In addition, because fuel supply during non-winter months does not face the constraints experienced in winter months, shifts in fuel consumption between CMR and ESI cases do not occur in the non-winter month analyses. Given these factors, our quantitative analysis of real-time market outcomes produces the same outcomes in the CMR and ESI cases. As a result, impacts that are based on changes in real-time outcomes (e.g., production costs and operational benefits) are not assessed because our analysis would not quantify any change.

While we do not quantify these effects, we expect that ESI would create reliability benefits and reductions in production costs during non-winter months, as well as during winter months. Production costs could be reduced through the more orderly procurement of reserves day-ahead. Reliability benefits could be created by increasing the supply of energy in real-time to mitigate unanticipated contingencies. Such reliability benefits are most likely to occur under circumstances when large, sustained system contingencies occur, leaving the system vulnerable and straining the system's ability to recover 10- and 30-minute reserves consistent with FERC/NERC standards. Further, changes in the composition of electric and natural gas infrastructure in the New England (and surrounding) region could create market conditions in which energy security concerns become more pressing in non-winter months, in addition to winter months. Under these circumstances, we would expect the reliability benefits that ESI would provide during non-winter months would increase beyond its ability to address unanticipated contingencies.

ESI would be expected to lead to an increase in payments by load during non-winter months. Estimated increases in payments are $89 million (3.6 percent) and $125 million (4.6 percent) in the Moderate and Severe Cases, respectively, over the nine-month non-winter period.

1. Compensation to Energy Supply

Table 28 provides the change in payments to energy for the three Central Cases. Changes reflect both the impact on LMPs and the additional FER payments. Across the two cases, DA LMPs are reduced by $0.18 per MWh in the Moderate Case and $0.23 per MWh in the Severe Case. These LMP changes are driven by the increase in energy supply that clears the DA market. Because LMPs are set consistent with the demand bids (not supply offers) when the EIR constraint is binding, LMPs are reduced when cleared energy supply increases. But, suppliers of physical DA energy receive FER payments, in addition to the LMP. Average FER payments are $0.76 per MWh in the Moderate Case and $1.12 per MWh in the Severe Case. Accounting for the net effect of these two components, total payments to DA energy increase in the two cases by $0.58 per MWh (Moderate Case) and $0.89 per MWh (Severe Case).

Table 28. Non-Winter Average DA Payments to Generators

CMR vs ESI ($ per MWh)

	CMR	ESI				Change	
Case	Day-Ahead LMP [A]	Day-Ahead LMP [B]	FER [C]	Day-Ahead LMP + FER [D]=[B]+[C]	Real-Time LMP [E]	Day-Ahead LMP [B]-[A]	Day-Ahead LMP + FER [D]-[A]
Moderate Case	$27.90	$27.72	$0.76	$28.48	$28.35	($0.18)	$0.58
Severe Case	$29.81	$29.58	$1.12	$30.71	$30.65	($0.23)	$0.89

2. Prices for ESI Ancillary Services

The ESI proposal introduces new DA energy option products to the New England energy markets. **Table 29** reports average award prices for these products for the Non-Winter Cases. These prices are weighted averages, reflecting the quantity of each product needed in each hour.

Average ESI product prices are relatively consistent between Cases for GRC10, GRC30 and RER, ranging from $6.35 to $7.81 per MWh. For these products, the quantities are assumed to be the same in all hours, although in fact these quantities may differ from hour to hour.

Weighted average prices for EIR are higher than for the other ESI products, at $12.72 per MWh in the Moderate Case and $31.31 per MWh in the Severe Case. This occurs because the weights – EIR quantity – vary by hour and EIR prices tend to be higher in hours when EIR quantities are higher. Thus, even though prices in each hour for ESI products tend to be relatively similar, the weighted average EIR price is greater than for the other ESI products.

Table 29. Non-Winter Average DA Energy Option Clearing Prices
($ per MWh)

Case	EIR/FER	GCR10	GCR30	RER
Moderate Case	$12.72	$6.36	$6.35	$6.35
Severe Case	$31.31	$7.81	$7.80	$7.80

3. Supply of Energy and DA Energy Options

Consistent with the winter Central Cases, introduction of the EIR requirements causes the market to clear additional DA energy when there would otherwise be a gap between cleared energy supply and the load forecast. **Table 30** quantifies these adjustments, showing the changes in DA energy by resource type between CMR and ESI. Under CMR, the total energy clearing in the DA market ranges between 88.0 and 90.2 TWh across Cases (column [A]). By contrast, under ESI, total cleared DA energy ranges between 89.6 and 91.5 TWh (column [B]). Thus, DA energy supply increases by 1.4 and 1.6 TWh, an increase of 1.5% and 1.8%, respectively, compared to current market rules (column [D]). These increases in DA energy happen as a consequence of both the co-optimization of DA energy and EIR, and adjustments by demand (both virtual and physical) to maintain convergence between the day-ahead and expected real-time energy prices. While DA energy increases, there remains a gap between cleared DA energy and the forecast load in some hours. However, this gap is small, only 7.0 and 10.8 GWh, less than 0.1% of total load in both Cases.

Table 30. Non-Winter Changes in Cleared DA Energy
CMR vs ESI, Central Cases

	CMR	ESI		Difference	Real-Time Comparison	
	Day-Ahead Energy	Day-Ahead Energy	Cleared EIR	Day-Ahead Energy	Real-Time Demand	Energy + EIR
Case	[A]	[B]	[C]	[D] = [B] - [A]		[E] = [B] + [C]
Moderate Case	87,970,357	89,587,167	6,983	1,616,810	88,287,439	89,594,149
Severe Case	90,175,883	91,534,279	10,848	1,358,396	90,053,188	91,545,127

While overall DA energy supplies, including DA energy and DA energy options, increase in aggregate in both non-winter Cases, these impacts vary across resource types. **Table 31** and **Table 32** shows the impact of ESI on the products supplied in the DA markets across resource types. While there are differences, the direction and magnitude of these impacts is very similar between the two non-winter Cases.

Compared to current market rules, ESI leads to a shift in the supply of DA energy across resource types. Nearly all resources increase the supply of DA energy, with the largest increases for combined cycle units (dual-fuel and gas-only), and smaller amounts for other resource types. DA energy options are supplied by a mix of resources, including (in order of quantity supplied) pumped storage, combustion turbines (all fuel types), hydro power and combined cycle units (dual fuel and gas-only). These supply patterns are similar to the patterns observed in the winter month Cases.

Table 31. Non-Winter Energy and DA Energy Options by Resource Type
CMR vs ESI, Central Case, Severe Case (MWh)

Resource Type	Nameplate Capacity (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	267	51	168	0	117
Battery Storage	458	125,906	125,906	0	0
Biomass/Refuse	830	4,295,501	4,296,836	0	1,336
Coal	531	252,245	272,980	38,705	20,735
Dual Fuel - CC	5,884	17,699,486	18,103,706	1,166,872	404,220
Dual Fuel - GT	1,237	792,172	797,347	4,154,426	5,175
Fuel Cell	21	6,460	7,478	0	1,018
Gas - CC	7,411	22,111,781	22,998,479	1,404,690	886,699
Gas - GT	364	25,141	28,663	1,256,090	3,522
Hydro	1,987	4,085,436	4,085,436	3,299,392	0
Imports	2,850	15,346,463	15,360,004	0	13,541
Nuclear	3,344	19,528,105	19,528,105	0	0
Offshore Wind	800	2,398,596	2,398,596	0	0
Oil Only - Steam	3,698	1,418	17,619	17,619	16,202
Oil Only - CT	2,114	0	37	2,970,196	37
Pumped Storage	1,778	1,882,553	1,882,553	9,457,666	0
Solar	1,671	1,863,549	1,863,549	0	0
Wind	1,401	2,448,824	2,448,824	0	0

Table 32. Non-Winter Energy and DA Energy Options by Resource Type
CMR vs ESI, Central Case, Moderate Case (MWh)

Resource Type	Nameplate Capacity (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	267	11	32	0	21
Battery Storage	458	125,906	125,906	0	0
Biomass/Refuse	830	4,249,546	4,261,671	0	12,125
Coal	531	167,617	177,373	23,906	9,755
Dual Fuel - CC	5,884	16,409,650	17,270,052	1,109,309	860,402
Dual Fuel - GT	1,237	777,989	776,349	4,203,326	(1,640)
Fuel Cell	21	4,929	5,537	0	608
Gas - CC	7,411	21,220,038	21,872,957	1,446,084	652,920
Gas - GT	364	10,993	7,395	1,270,802	(3,598)
Hydro	1,987	4,464,248	4,464,248	3,093,115	0
Imports	2,850	15,011,434	15,062,719	0	51,285
Nuclear	3,344	19,520,806	19,520,806	0	0
Offshore Wind	800	2,398,673	2,398,673	0	0
Oil Only - Steam	3,698	114	2,527	2,527	2,413
Oil Only - CT	2,114	0	0	5,063,873	0
Pumped Storage	1,778	1,882,553	1,882,553	7,542,569	0
Solar	1,671	1,968,609	1,968,609	0	0
Wind	1,401	2,472,822	2,472,822	0	0

4. *Impact of Customer Payments*

Total change in customer payments due to the ESI proposal will reflect a combination of factors: total LMP payments through DA and RT markets; compensation for meeting the FER, and new payments made in the DA market for DA energy options. **Table 33** summarizes the net impact of these three components on total customer payments.

Total payments increase by $89 million in the Moderate Case, and $125 million in the Several Case. Total payments for energy – LMPs and FER payments – increase in both cases, by $50 million and $78 million in the Moderate and Severe Cases, respectively. Similarly, net payments for ESI products are $38 million and $47 million, respectively. In total, these changes represent a 3.6% and 4.6% increase in payments for the Moderate and Severe Cases, respectively.

Table 33. Non-Winter Total Payments by Case ($ Million)

		Moderate Case				Severe Case			
Product / Payment		**CMR**	**ESI**	**Difference**		**CMR**	**ESI**	**Difference**	
Energy and RT Operating Reserves	[A]	$2,473	$2,455	-$18	-0.7%	$2,697	$2,672	-$25	-0.9%
DA Energy Option									
DA Option Payment			$151				$186		
EIR			$0				$0		
RER			$50				$62		
GCR10			$67				$83		
GCR30			$34				$41		
RT Option Settlement			-$113				-$139		
Net DA Ancillary	[B]		$38				$47		
FER Payments	[C]		$68				$103		
Total Payments	[A+B+C]	$2,473	$2,562	$89	3.6%	$2,697	$2,822	$125	4.6%

5. Resource Net Revenue

As with the winter analysis, the impact of ESI on the net revenues earned by resources in non-winter months would depend on a combination of factors. In aggregate, changes in payments by load would lead to corresponding changes in revenues to generators. Thus, in Cases when payments to load are expected to increase, this would be expected to lead to a corresponding increase in revenues to resource owners.

Table 34 and **Table 35** provide the average net revenues by resource type for the Frequent, Extended and Infrequent Cases, respectively. With a few exceptions, net revenues increase in both Cases. However, the magnitude of these changes varies across resources. These differences depend on a variety of factors, including resource-specific operational characteristics, such as plant operating efficiency and the ability to provide ESI ancillary services.

Table 34. Non-Winter Average Net Revenues by Resource Type, Severe Case ($ per MW)

	Net Revenue ($/MW)		
Resource Type:	CMR [A]	ESI [B]	Change [C] = [B] - [A]
Dual Fuel - CC	$9,872	$13,158	$3,286
Dual Fuel - GT	$8,380	$15,971	$7,591
Gas Only - CC	$10,264	$13,555	$3,291
Gas Only - GT	$1,382	$9,027	$7,645
Oil Only - Steam	$192	$241	$50
Oil Only - CT	$606	($83)	($689)
Coal	$9,411	$9,394	($18)
Biomass/Refuse	$145,754	$149,222	$3,468
Fuel Cell	$6,964	$7,457	$493
Hydro	$69,230	$74,225	$4,995
Nuclear	$170,861	$174,801	$3,940
Solar	$32,442	$33,300	$858
Wind	$53,491	$54,569	$1,078
Offshore Wind	$88,152	$89,830	$1,678

Table 35. Non-Winter Average Net Revenues by Resource Type, Moderate Case ($ per MW)

	Net Revenue ($/MW)		
Resource Type:	CMR [A]	ESI [B]	Change [C] = [B] - [A]
Dual Fuel - CC	$7,914	$9,899	$1,985
Dual Fuel - GT	$6,782	$12,721	$5,940
Gas Only - CC	$8,265	$10,323	$2,058
Gas Only - GT	$562	$6,823	$6,261
Oil Only - Steam	$23	$47	$24
Oil Only - CT	$353	$2,502	$2,149
Coal	$5,353	$6,296	$943
Biomass/Refuse	$134,779	$137,212	$2,433
Fuel Cell	$3,463	$3,616	$153
Hydro	$67,892	$71,579	$3,686
Nuclear	$158,399	$161,162	$2,764
Solar	$31,080	$31,482	$402
Wind	$49,772	$50,583	$811

C. Scenario Analysis

As described earlier, the Central Case represents a potential future scenario for 2025/26 in which system resources and market conditions remain (relatively) unchanged from today. While the Central Case is reasonably plausible, there is substantial uncertainty about how market and system conditions will change between now and the implementation of ESI, if approved.

We have therefore modeled a number of additional Scenarios. These Scenarios start with the Central Case analysis and change one (or several) key assumptions, but otherwise keep all assumptions the same. For each Scenario, we evaluate the same Frequent, Extended and Infrequent Cases that are evaluated in the Central Case.

Several different types of scenarios are evaluated. ***First***, we consider ESI's impacts under ***different assumptions about future market conditions***. **Table 36** describes these Scenarios. These Scenarios will help better understand how ESI would be expected to affect market outcomes under a range of market and system conditions, including those with more and less frequent stressed system conditions, and those with higher costs. Particular future assumptions tested include changes to the region's mix of electric power resources, the infrastructure that delivers fuel to the region, and load growth.

Table 36. Scenarios Evaluating Changes in Market or System Conditions

No Fuel-Related Market Response	
Risk Premium x1.25	"Central Case" with DA energy option offers calculating using risk premia set at 125% of Central Case levels.
Supply Shocks	Unexpected real-time outages, experienced during coldest portion of historic winter.
Shock HQ 1 Day	Supply shock (outage) fo 1,364 MW is modeled in real-time market, but not modeled in day-ahead market. - Frequent Stressed Conditions: January 3, 2014 (average temperature 11.64 F); - Extended Stressed Conditions: January 1, 2018 (average temperature 2.72 F); - Infrequent Stressed Conditions: December 6, 2016 (average temperature 4.77 F).
Shock HQ 5 Days	Supply shock of 1,364 MW is modeled in Day-1 real-time market, but not expected in Day 1 day-ahead market. Resource is expected out day-ahead in remaining days (Days 2-5). - Frequent Stressed Conditions: January 21-25, 2014 (average temperature 12.83 F); - Extended Stressed Conditions: December 28, 2017 - January 1 2018 (average temperature 5.68 F); - Infrequent Stressed Conditions: January 6-10, 2016 (average temperature 19.07 F).
High LNG Supply	Assume additional LNG availability of 0.4 Bcf/day to both ESI and CMR cases (all winter severities). Under ESI, assume an incremental 0.4 Bcf/day available for LNG forward contracts, for a total of 0.52 Bcf/day available for forward contracts.
Low LNG Supply	Assume reduced LNG availability of 0.12 Bcf/day in both ESI and CMR cases for all winter severities (corresponding to LNG forward contract).
High Load	Load is increased by 5%, with no other modeling changes.
Oil Retirements	For oil retirement scenarios: an additional ~1,000 MW of oil resources retired.
With Renewable Replacement	3,824 MW nameplate (1,400 MW derated) of new offshore wind, 1,200 MW of new hydro imports, and 0.3 Bcf/day of additional LNG capacity added.
Nuclear Retirements	For nuclear retirement scenarios: an additional ~3,500 MW of nuclear resources retired.
With Renewable Replacement	8,824 MW nameplate (3,000 MW derated) of new offshore wind, 5,333 MW nameplate (800 MW derated) of new onshore wind, 1,200 MW of new hydro imports, and 0.6 Bcf/day of additional LNG capacity added.
With Fuel-Related Market Response	
Oil Retirements	For oil retirement scenarios: an additional ~1,000 MW of oil resources retired.
With Gas Replacement	2,500 MW of new natural gas CC resources, none with dual-fuel capability, and 0.3 Bcf/day of additional NG supply
With Gas / Dual Fuel Replacement	2,500 MW of new natural gas CC resources, 50% with dual-fuel capability, and 0.3 Bcf/day of additional NG supply
Nuclear Retirements	For nuclear retirement scenarios: an additional ~3,500 MW of nuclear resources retired.
With Gas Replacement	5,000 MW of new natural gas CC resources, none with dual-fuel capability and 0.7 Bcf/day of additional NG supply
With Gas / Dual Fuel Replacement	5,000 MW of new natural gas CC resources, 50% with dual-fuel capability, and 0.7 Bcf/day of additional NG supply

Second, we consider the impacts of ***different ESI designs***. **Table 37** describes these Scenarios. These Scenarios includes designs that exclude certain ESI products included in the ISO-NE proposal, and designs with an energy option strike price that differs from the ISO-NE proposal. These proposals will help better understand how different elements of the ESI proposal affect market and operational outcomes.

Table 37. Scenarios Evaluating ESI Designs

No Fuel-Related Market Response	
RER Plus	"Central Case" with RER requirement set to 150% of Central Case level (1,800 MW).
Strike Plus $10	"Central Case" with DA energy option strike price = Central Case strike price + $10 in all hours; adjustment affects all calculations, incuding risk premia.
With Fuel-Related Market Response	
No EIR/RER	"Central Case" with no RER nor EIR requirement. Under ESI, there is no incremental fuel relative to amounts assumed under CMR.
No RER	"Central Case" with no RER requirement. Under ESI, incremental fuel (i.e., relative to CMR) is assumed to be one-half of the incremental fuel amounts assumed in the Central Case.

Third, we consider one Scenario in which the ***ESI design causes no change in the fuel inventory and refueling decisions of market participants***. We do not evaluate this Scenario because we expect there to be no change in fuel inventories if ESI were adopted (recall, Section IV.1 found that ESI generally increases the incentive to hold fuel relative to current market rules). Rather, this Scenario provides information on the impact of the ESI proposal, apart from the impact of the incremental fuel inventory due to the new incentives created by ESI.

Fourth, we consider two ***non-winter Scenarios***, both involving different ESI design. One Scenario assumes no RER product (analogous to the "No RER" winter Scenario), while the second Scenario assumes a strike price set $10 per MWh above the expected RT LMP (analogous to the "Strike Plus $10" winter Scenario).

While our model captures many of the market adjustments that occur with new Scenario assumptions, it does not endogenously capture all effects. In particular, the model does not endogenously adjust aggregate fuel supplies or resource-level fuel inventory decisions for changes in market design or market conditions.[44] In general, however, we would expect market responses to depend on underlying assumptions about market tightness and market design. For example, if all of the nuclear power plants in New England were to retire, we would expect new resources to enter the market, along with potential changes in fuel supply and demand, such as new sources of LNG supplies, new infrastructure (e.g., LDC peak shavers), and new dual fuel capability.

While we expect some degree of market response in many Scenarios, the magnitude of this expected response varies. Thus, for Scenarios in which we expect the market response to be comparatively smaller, we make no change from the Central Case, whereas in Scenarios in which we expect a larger market response, we modify certain assumptions related to fuel from the Central Case.

Table 36 and **Table 37 i**dentify the Scenarios with fuel assumptions that are the same as the Central Case, and the Scenarios with fuel assumptions that differ from the Central Case. In Scenarios assuming substantial retirements or oil or nuclear resources with replacement by natural gas-fired resources, we assume a fuel

[44] In principal, these adjustments can include market, regulatory and policy responses to market conditions. With regard to regulatory and policy responses, we take no position on the form of any such policy response, but acknowledge that such response could occur.

market response to the increase in demand for natural gas that would occur under such Scenarios. This market response could come in one of many different forms, such as additional natural gas supplies through an LNG terminal, development of new LDC peak-shaving facilities to relieve reliance on the remaining LNG terminals, or additional dual-fuel capability (which would also reduce the dependence on the region's gas infrastructure). In these Scenarios, we assume the incremental fuel supply is present in both the CMR and ESI Cases. Likewise, several Scenarios assume changes in ESI designs that would be expected to reduce the incentives to retain fuel supplies relative to the ISO's ESI proposal. In some of these Scenarios, we reduce the quantity of incremental fuel in the ESI Case to reflect this impact, but keep the assumptions in the CMR Case unchanged.

There are many Scenarios that assume no changes in fuel supplies or inventories, this does not suggest imply that it is reasonable to assume that no such changes would occur, in actuality. Moreover, although we make best efforts to develop reasonable assumptions about fuel supply or inventory response in each Scenario, these assumptions are not forecasts or precisely estimated adjustments. Instead, we make reasonable assumptions, consistent with the deterministic scenario approach we employ generally. Thus, when comparing *between* Scenarios, care should be taken to recognize that the counterfactual assumptions about fuel availability (market supplies and inventory) and potentially other factors, may make certain comparisons inappropriate. Nonetheless, these Scenarios do help to shed further light on the possible impacts of ESI across various market conditions and design changes, and also help to illustrate the model's sensitivities to key input assumptions.

The results of our Scenario analysis are reported in the body of this report and with additional detail in a supplemental appendix. In the body of this report, we provide the impacts (changes) on prices and payments, and the impacts (changes) on operational metrics indicative of potential reliability benefits. The supplemental appendix provides these results plus the impacts on shortages hours of day-ahead and real-time ancillary services, as well as the levels for the prices and payments, operational metrics, and shortage hours for both the CMR and ESI Cases.

1. Scenarios Evaluating Changes in Market or System Conditions

a) Risk Premium

The Risk Premium plus 25% Scenario assumes a 25% increase in all risk premia for DA energy options compared to the Central Case estimates. This Scenario provides information on the sensitivity of impacts to the cost of procuring the DA energy options. With the higher risk premia, total payments increased by $42, $29 and $13 million compared to Central Case payments for the Frequent, Extended and Infrequent Case, respectively. Most of this change in payments is due to the higher net cost of the DA energy options, which increase by $41, $25 and $10 million, respectively, in the Frequent, Extended and Infrequent Cases. By contrast, the net cost for energy (LMPs plus FER payments) remains relatively unchanged.

While this Scenario provides information on the sensitivity of impacts to general (uniform) shifts in the magnitude of the DA energy option offers, it is not intended to represent the potential impacts of the exercise of seller-side market power on market outcomes. Such analysis is outside the scope of this report, and may focus on the impacts, if any, during periods when supplies of DA energy and DA energy options are tightest, which are expected to be episodic, and not uniform across the winter months.

b) Supply Shocks

The supply shock Scenarios assume 1-day and 5-day supply contingencies, in which imports are reduced by 1,364 MW during stressed market conditions. In first day of both Scenarios, the resource is assumed to be available in the day-ahead market but not in the next day's real-time market. In the scenario with the prolonged 5-day shock, the unavailable resource is also excluded from the DA market in subsequent days.

In these Scenarios, ESI's impact on total payments is generally reduced relative to the Central Cases, but by relatively small amounts. In the 1-day Scenario, ESI's impact on total payment impacts is smaller than the Central Case, but only reduced by $9, $3 and $1 million for the Frequent, Extended and Infrequent Cases, respectively. The 5-day Scenario impacts on payments are also similar to the Central Case, although ESI's impact on payments in Frequent Case falls to $92 million from $132 million in the Central Case. These Cases illustrate that ESI can lower payments during periods of stressed conditions, including those in which contingencies occur. The reductions in payments occur because ESI's incentives for energy inventory would be expected to increase inventoried energy supply, which can lower LMPs during tight market conditions.

Detailed analysis of market outcomes illustrates how market responses to a supply contingency may differ under ESI as compared to current market rules. **Figure 27** shows RT LMPs during the supply contingency, while **Figure 28** shows the aggregate fuel oil inventory. With the higher fuel inventory, the market is able to maintain a supply of energy able to meet real-time loads plus reserve requirements. However, absent this incremental fuel, the system is short of operating reserves, which leads to higher market prices set at operating reserve penalty factors.

Figure 27. Real-Time LMPs during 5-Day Supply Shock

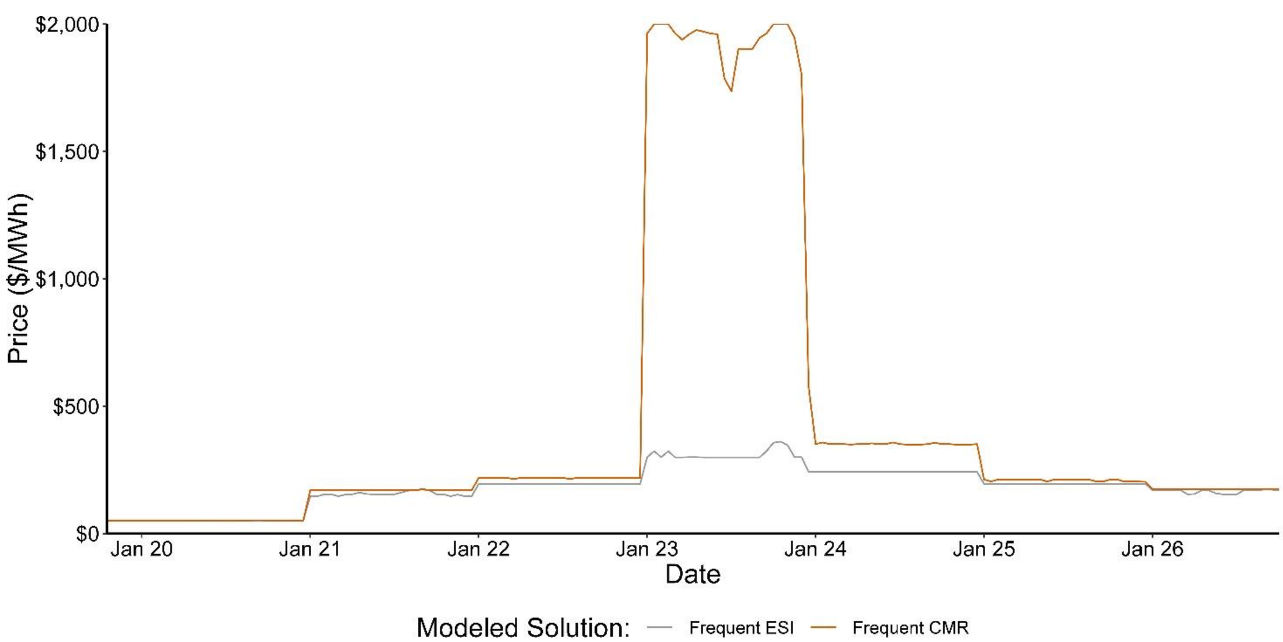
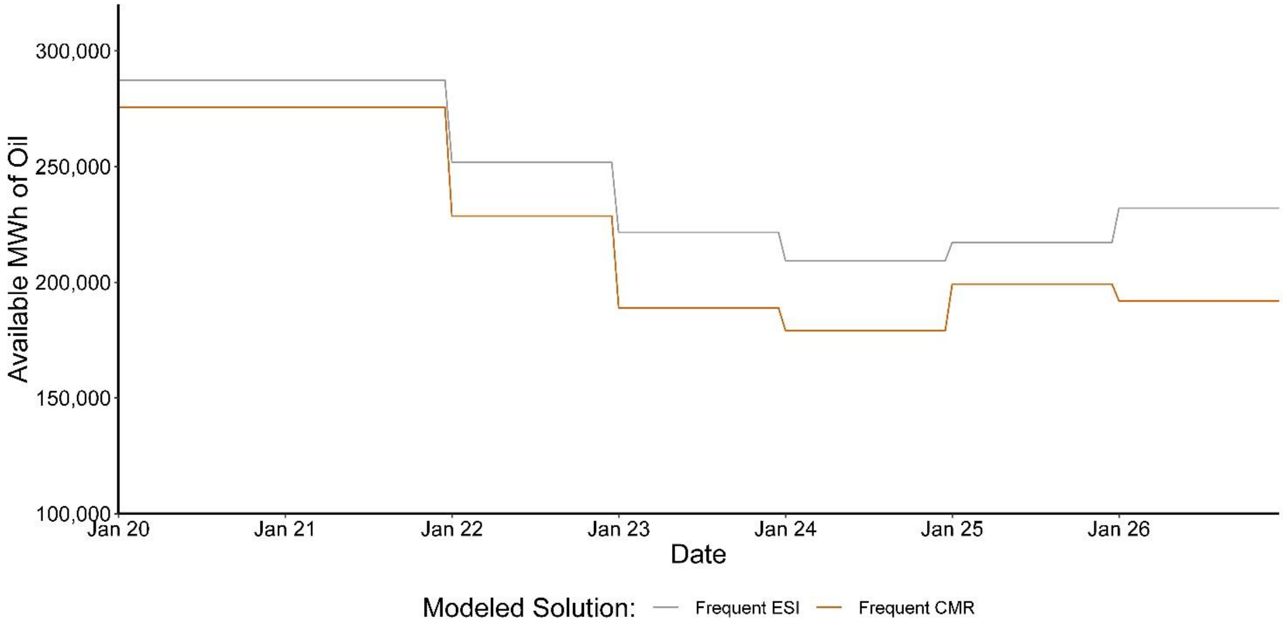


Figure 28. Aggregate Fuel Oil Inventory during 5-Day Supply Shock



Operational metrics generally show larger improvements consistent with reliability benefits compared to the Central Case. In the Frequent Case, ESI avoids three hours of operating reserve shortages that occur under current market rules during the 5-day Supply Shock. Metrics related to natural gas and oil supply generally show larger improvements than the Central Case, with improvements being the greatest in the Extended Case.

c) LNG Supply

The LNG Supply Scenarios consider both a higher quantity of LNG supply (increased by 0.4 bcf) and a lower quantity of LNG supply (decreased by 0.12 bcf) compared to the Central Case. The change in LNG supply is assumed in both the CMR and ESI Cases, and the amount of fuel incented by ESI is the same as the Central Case, although in actuality it would be reasonable to expect less fuel in the High LNG Scenario and more fuel in the Low LNG Scenario.

Compared to the Central Case, higher LNG supply would tend to reduce ESI's impact on total payments, while lower LNG supply would tend to increase total payments. These effects are largest during stressed market conditions. With the assumed higher quantity of LNG supply, ESI's impact on total payments is $50 million (Frequent Case) and $108 million (Extended Case). By contrast, with lower LNG supplies, total payments in the Frequent Case are $154 million higher with ESI (as compared to CMR) and in the Extended Case are $15 million lower with ESI (compared to CMR). In unstressed market conditions, the change in LNG supply leads to no meaningful change in payment impacts compared to the Central Case.

d) High Load

The High Load Scenario assumes higher load than is assumed in the Central Cases, with no adjustments to capacity or available energy inventory. With high load, ESI is estimated to reduce total payments by $322 and $256 million in the Frequent and Extended Cases, respectively, and increase payments by $35 million in the

Infrequent Case. As with other Scenarios, these impacts are substantially different for the stressed market conditions cases, and very similar for the unstressed market condition case. The reductions in payments in the stressed conditions cases are driven by the reduction in DA LMPs ($23.92 and $14.33 per MWh in the Frequent and Extended Cases, respectively) that occur because of the incremental energy inventory incented by ESI. Prices for FER and DA energy options are also larger than in the Central Case. However, the LMP reductions are sufficiently large to offset payment for these ancillary services.

ESI produces operational benefits, particularly under the Frequent and Extended stressed conditions Cases. These impacts vary in magnitude from the Central Case, larger in many but not all cases.

e) Retirements

Multiple retirement Scenarios are evaluated. We consider retirement of a set of at-risk oil resources (approximately 1,000 MW) and both remaining nuclear plants (Millbrook and Seabrook, approximately 3,500 MW). For both sets of assumed retirements, we run three distinct Scenarios with retired resources replaced by three different types of new resources: (i) renewable resources, (ii) all gas-only combined cycle resources, or (iii) a mix of gas-only and dual fuel combined cycle resources. Thus, in total, we evaluate six retirement Scenarios.

In these retirement Scenarios, we consider whether the retirements would likely prompt a market response in the fuels market, given the potential change in fuel demand from the electricity sector. When retirements are replaced by renewables, we do not assume any market response, as the renewables do not increase fuel demand. In the other Scenarios, the replacement of oil or nuclear plants with resources relying on natural gas will tend to increase demand for natural gas. We assume a corresponding market response that increases the potential supply of natural gas to the electricity sector. We do not identify the source of this supply, which, in principle, could come from LNG supplies (e.g., through the Northeast Gateway buoy), expanded dual fuel capacity, additional LDC "peak shaving" infrastructure (i.e., satellite LNG tanks), or other sources. The quantity of incremental fuel we assume reflects an evaluation of the change in LMPs with different levels of incremental natural gas, under the premise that these price signals would drive demand for increased supplies. In the oil retirement cases, we assume an additional 0.3 bcf of fuel, while in the nuclear cases we assume an additional 0.7 bcf. While we adjust the assumptions about aggregate fuel supply, we do not adjust assumptions about the response of market participants to ESI incentives.

When renewables replace the retired resources, total payments under ESI (compared to CMR) increase in 3 of 4 stressed Scenarios and in both Infrequent Scenarios. In the stressed scenarios, ESI's payment impact ranges from an increase of $149 million to a decrease of $35 million. These results are similar to the Central Case, although reductions in LMPs (due to ESI) tend to be lower and the net cost of ESI product are higher (as compared to CMR). For example, in the Extended Case, the reduction in average energy costs (due to ESI) is $6.43 per MWh in the Central Case compared to $2.66 per MWh when nuclear retirements are replaced by renewables. But, net payments for DA energy options fall from $32 million in the Central Case to $20 and $21 million for the oil and nuclear retirements, respectively.

When gas-only or a mix of gas-only and dual fuel replace the retired resources, payment impacts are much larger. These impacts reflect the sensitivity of the market outcomes as the region increases its reliance on natural gas resources. In the Frequent Case, total payments are $115 to $531 million higher with ESI, whereas in the Extended Case, total payments impacts range from an increase in payments of $274 million to a reduction in payments of $193 million. In the Infrequent Case, payment impacts range from increases of $19 to $35 million, similar to the Central Case. In all Scenarios, the incremental inventoried energy incented by ESI reduces LMPs, but net payments for energy increase in some cases (for example, all Frequent Cases) and decease in other cases (for example, 3 of 4 Extended Cases). Net payments for DA energy options range from $33 to $119 million across stressed Cases.

Table 38. Scenarios Evaluating Changes in Market or System Conditions - LMPs & Payments, Frequent Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Frequent Case						
Central Case	($5.49)	$7.76	$27.00	$67	$66	$132
No Fuel-Related Market Response						
Risk Premium x1.25	($5.52)	$7.80	$32.33	$67	$107	$174
Shock HQ 1 Day	($5.62)	$7.78	$27.00	$57	$65	$123
Shock HQ 5 Days	($19.35)	$20.59	$33.19	($23)	$115	$92
High LNG Supply	($9.02)	$6.17	$24.64	($98)	$48	($50)
Low LNG Supply	($6.86)	$9.39	$29.10	$77	$77	$154
High Load	($23.92)	$11.99	$30.78	($412)	$90	($322)
Oil Retirements; Renewable Replacement	($4.76)	$5.62	$23.46	$42	$40	$82
Nuclear Retirements; Renewable Replacement	($5.21)	$6.61	$25.05	$96	$53	$149
With Fuel-Related Market Response						
Oil Retirements; Gas Replacement	($5.60)	$18.75	$33.69	$412	$119	$531
Oil Retirements; Gas / Dual Fuel Replacement	($7.17)	$8.75	$28.71	$41	$74	$115
Nuclear Retirements; Gas Replacement	($5.04)	$9.40	$29.51	$126	$78	$204
Nuclear Retirements; Gas / Dual Fuel Replacement	($3.99)	$9.47	$28.07	$166	$72	$238

Table 39. Scenarios Evaluating Changes in Market or System Conditions - LMPs & Payments, Extended Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Extended Case						
Central Case	($6.43)	$3.55	$14.46	($100)	$32	($69)
No Fuel-Related Market Response						
Risk Premium x1.25	($6.47)	$3.71	$17.66	($97)	$57	($40)
Shock HQ 1 Day	($6.58)	$3.59	$14.44	($104)	$32	($72)
Shock HQ 5 Days	($7.14)	$4.17	$15.24	($104)	$38	($66)
High LNG Supply	($6.01)	$2.26	$13.03	($129)	$21	($108)
Low LNG Supply	($7.28)	$5.70	$16.28	($60)	$45	($15)
High Load	($14.33)	$5.69	$16.44	($303)	$46	($256)
Oil Retirements; Renewable Replacement	($4.10)	$2.17	$12.98	($55)	$20	($35)
Nuclear Retirements; Renewable Replacement	($2.66)	$2.00	$13.10	$13	$21	$34
With Fuel-Related Market Response						
Oil Retirements; Gas Replacement	($9.05)	$4.52	$15.82	($160)	$38	($122)
Oil Retirements; Gas / Dual Fuel Replacement	($10.30)	$3.69	$15.02	($225)	$33	($193)
Nuclear Retirements; Gas Replacement	($8.33)	$14.92	$20.36	$192	$81	$274
Nuclear Retirements; Gas / Dual Fuel Replacement	($9.07)	$4.26	$15.03	($170)	$35	($135)

Table 40. Scenarios Evaluating Changes in Market or System Conditions - LMPs & Payments, Infrequent Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Infrequent Case						
Central Case	($1.20)	$1.94	$5.75	$20	$15	$35
No Fuel-Related Market Response						
Risk Premium x1.25	($1.30)	$2.13	$7.13	$22	$25	$48
Shock HQ 1 Day	($1.24)	$1.96	$5.76	$19	$15	$34
Shock HQ 5 Days	($1.28)	$2.06	$5.88	$21	$16	$36
High LNG Supply	($0.76)	$1.58	$5.71	$21	$14	$36
Low LNG Supply	($1.50)	$2.07	$5.79	$15	$15	$30
High Load	($1.45)	$2.16	$5.82	$20	$15	$35
Oil Retirements; Renewable Replacement	($1.28)	$1.45	$5.66	$18	$14	$31
Nuclear Retirements; Renewable Replacement	($1.72)	$1.70	$5.71	$27	$14	$42
With Fuel-Related Market Response						
Oil Retirements; Gas Replacement	($1.01)	$1.77	$5.71	$20	$14	$35
Oil Retirements; Gas / Dual Fuel Replacement	($1.14)	$1.76	$5.69	$16	$14	$30
Nuclear Retirements; Gas Replacement	($1.16)	$1.94	$5.74	$21	$15	$35
Nuclear Retirements; Gas / Dual Fuel Replacement	($1.71)	$1.97	$5.70	$5	$14	$19

Table 41. Scenarios Evaluating Changes in Market or System Conditions - Operational Metrics, Frequent Case

	System Reliability (Change)				
Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Frequent Case					
Central Case	0	(2,897,177)	24,512	15,204	(16,413)
No Fuel-Related Market Response					
Risk Premium x1.25	0	(2,900,847)	24,421	15,204	(16,536)
Shock HQ 1 Day	0	(2,858,688)	24,512	15,661	(14,689)
Shock HQ 5 Days	(3)	(2,977,660)	27,997	15,904	(14,745)
High LNG Supply	0	(5,097,543)	14,821	17,475	(33,510)
Low LNG Supply	0	(1,906,929)	29,003	16,925	(8,740)
High Load	0	(3,618,832)	13,663	17,991	(23,414)
Oil Retirements; Renewable Replacement	0	(1,117,137)	20,525	14,228	(1,134)
Nuclear Retirements; Renewable Replacement	0	(878,402)	20,550	15,364	(5,703)
With Fuel-Related Market Response					
Oil Retirements; Gas Replacement	0	(6,395,750)	26,098	10,679	731
Oil Retirements; Gas / Dual Fuel Replacement	0	(6,272,248)	16,245	13,935	(8,465)
Nuclear Retirements; Gas Replacement	0	(12,322,023)	10,131	9,608	(9,084)
Nuclear Retirements; Gas / Dual Fuel Replacement	0	(12,852,218)	32,986	13,687	(14,422)

Table 42. Scenarios Evaluating Changes in Market or System Conditions - Operational Metrics, Extended Case

	System Reliability (Change)				
Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Extended Case					
Central Case	0	(943,020)	32,663	14,022	(7,527)
No Fuel-Related Market Response					
Risk Premium x1.25	0	(943,020)	32,663	14,022	(7,527)
Shock HQ 1 Day	0	(943,020)	34,807	14,918	(1,041)
Shock HQ 5 Days	0	(1,009,333)	28,426	15,398	(7,076)
High LNG Supply	0	(3,440,918)	40,214	15,327	(5,925)
Low LNG Supply	0	(79,946)	26,394	15,528	(11,646)
High Load	0	(851,854)	25,828	15,910	(6,214)
Oil Retirements; Renewable Replacement	0	(614,918)	10,799	12,116	(3,790)
Nuclear Retirements; Renewable Replacement	0	(332,387)	28,510	12,340	(14,390)
With Fuel-Related Market Response					
Oil Retirements; Gas Replacement	0	(3,484,459)	10,230	13,081	1,860
Oil Retirements; Gas / Dual Fuel Replacement	0	(3,497,787)	12,036	15,045	(4,948)
Nuclear Retirements; Gas Replacement	0	(7,662,525)	20,129	12,803	(8,296)
Nuclear Retirements; Gas / Dual Fuel Replacement	0	(7,277,589)	12,911	16,611	(14,536)

Table 43. Scenarios Evaluating Changes in Market or System Conditions - Operational Metrics, Infrequent Case

Scenario Name/Acronym	System Reliability (Change) Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Infrequent Case					
Central Case	0	NA	6,753	11,656	(77)
No Fuel-Related Market Response					
Risk Premium x1.25	0	NA	6,753	11,656	(77)
Shock HQ 1 Day	0	NA	7,237	12,184	(46)
Shock HQ 5 Days	0	NA	6,569	12,068	2,228
High LNG Supply	0	NA	14,294	10,452	(4,307)
Low LNG Supply	0	NA	22,417	13,526	(9,127)
High Load	0	NA	14,520	12,955	(3,628)
Oil Retirements; Renewable Replacement	0	NA	14,728	12,037	(5,228)
Nuclear Retirements; Renewable Replacement	0	NA	8,562	11,244	(1,148)
With Fuel-Related Market Response					
Oil Retirements; Gas Replacement	0	NA	10,830	12,482	3,980
Oil Retirements; Gas / Dual Fuel Replacement	0	NA	30,811	14,288	(16,026)
Nuclear Retirements; Gas Replacement	0	NA	7,201	11,064	2,498
Nuclear Retirements; Gas / Dual Fuel Replacement	0	NA	35,900	16,738	(22,968)

2. Scenarios Evaluating Changes in ESI Design

a) Change in ESI Product Quantities

Several Scenarios consider changes in product quantities, including: No RER, No EIR/RER and RER Plus. Because the assumptions about market participant response differ in each of these Scenarios, they each provide different information about ESI's expected impacts.

The RER Plus Case assumes an additional 600 MW of RER. Compared to the Central Case, the additional RER increases payments by $99, $50 and $16 million in the Frequent, Extended and Infrequent Cases, respectively. These estimates may overstate the true cost impacts, as no change in fuel-inventory response by market participants is assumed, and the procurement of additional RER (and its corresponding impact on resource revenues) may incent the procurement of additional fuel.

Dropping the RER or dropping both the RER and the EIR reduces lower payments in most, but not all, Cases, reflecting the reduction in payments due to the lower quantity of AS procured, which is (partially) offset by a reduction in incented energy inventory, which lowers costs. With no RER, payments are reduced relative to the Central case by $73, $48 and $9 million in the Frequent, Extended and Infrequent Cases, respectively. In the no RER/EIR, payments are reduced by $108 million and $29 million in the Frequent and Infrequent Cases, and increase by $83 million in the Extended Case.

With different assumed energy inventory response to ESI's incentives, the operational metrics differ from the Central Case. With No RER, which assumes 50% on the fuel incentive response, the operational metrics are improved in 8 of 11 instances, compared to the Central Case. With No RER/EIR, there is minimal change in these metrics compared to CMR, consistent with the assumption that there is no incremental fuel incented by ESI.

b) Change in Strike Price

The Strike Price + $10 Scenario assumes a strike price set at $10 above the level assumed in the Central Case, where the hourly strike price equals the expected RT LMP, based on the DA LMP. Compared to the Central Case, total payments are reduced by $1, $15 and $13 million in the Frequent, Extended and Infrequent Cases, respectively. These reductions reflect several effects. First, the total cost of the DA option procurement is reduced. Compared to the Central Case, the higher strike price reduces the average DA energy option price by $4.09, $3.98 and $3.07 per MWh in the Frequent, Extended and Infrequent Cases, respectively. The lower option prices do not result in direct reductions in payments, however, because the gains in real-time settlement of these options are also reduced. Thus, in total, the higher strike price reduces the net cost of the procuring ESI products by $5, $7 and $8 million in the Frequent, Extended and Infrequent Cases, respectively. Second, the cost for energy, reflecting LMPs and FER payments, also decreases in the Extended and Infrequent Case by $9 and $5 million, respectively, while increasing by $2 million in the Frequent Case.

No change in energy inventories are assumed in this Case, thus the operational metrics do not meaningfully change compared to the Central Case. While our analysis does not quantify an impact to reliability benefits, we would nonetheless expect that ESI would create less reliability benefit because, with a reduced closeout cost risk, the incentives to increase inventoried energy would be diminished.

3. No Incremental Fuel under ESI

We evaluate a Scenario in which we assume no incremental energy inventory under ESI, but otherwise keep all assumptions unchanged from the Central Case. We do not think this is a realistic scenario, but provide it as a means to better understand the impacts of ESI, independent of its effect on incentives to improve resource deliverability of energy in real-time.

Without incremental energy inventory, total payments are $398, $226 and $40 million higher under ESI compared to the CMR Case. These impacts are largely driven by increased payments to DA energy, driven by FER payments. For example, in the Extended Case, the average FER price is $3.55 per MWh in the Central Case, which increases to $7.78 per MWh with no incremental fuel inventory, and increase of $4.23 per MWh. Without incremental energy inventory, the number of ESI shortage hours increases substantially. For example, in the Frequent Case, there are 59 RER shortage hours in the Central Case but 111 RER shortage hours without incremental energy inventory.

Table 44. Scenarios Evaluating Changes in ESI Design - LMPs & Payments, Frequent Case

Scenario Name/Acronym	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Frequent Case						
Central Case	($5.49)	$7.76	$27.00	$67	$66	$132
No Fuel-Related Market Response						
RER Plus	($5.37)	$9.48	$30.61	$126	$105	$231
Strike Plus $10	($5.41)	$7.76	$22.91	$69	$61	$131
With Fuel-Related Market Response						
No EIR/RER	$0.06	NA	$22.46	$3	$21	$24
No RER	($4.36)	$5.63	$22.92	$35	$25	$59
No Incremental Oil under ESI						
No Incremental Oil under ESI	($1.06)	$11.00	$29.87	$314	$84	$398

Table 45. Scenarios Evaluating Changes in ESI Design - LMPs & Payments, Extended Case

Scenario Name/Acronym	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Extended Case						
Central Case	($6.43)	$3.55	$14.46	($100)	$32	($69)
No Fuel-Related Market Response						
RER Plus	($6.31)	$4.36	$16.17	($71)	$51	($19)
Strike Plus $10	($6.56)	$3.40	$10.48	($109)	$25	($84)
With Fuel-Related Market Response						
No EIR/RER	$0.21	NA	$11.43	$7	$7	$14
No RER	($5.83)	$2.28	$11.30	($122)	$6	($117)
No Incremental Oil under ESI						
No Incremental Oil under ESI	($2.39)	$7.78	$17.49	$166	$60	$226

Table 46. Scenarios Evaluating Changes in ESI Design - LMPs & Payments, Infrequent Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Infrequent Case						
Central Case	($1.20)	$1.94	$5.75	$20	$15	$35
No Fuel-Related Market Response						
RER Plus	($1.53)	$2.44	$6.71	$25	$26	$51
Strike Plus $10	($0.85)	$1.35	$2.68	$15	$7	$22
With Fuel-Related Market Response						
No EIR/RER	($0.00)	NA	$5.01	($0)	$7	$6
No RER	($1.05)	$1.76	$5.04	$19	$7	$26
No Incremental Oil under ESI						
No Incremental Oil under ESI	($1.02)	$1.94	$5.77	$26	$15	$40

Table 47. Scenarios Evaluating Changes in Market or System Conditions - System Reliability, Frequent Case

	System Reliability (Change)				
Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Frequent Case					
Central Case	0	(2,897,177)	24,512	15,204	(16,413)
No Fuel-Related Market Response					
RER Plus	0	(2,909,342)	23,866	15,276	(16,538)
Strike Plus $10	0	(2,900,051)	24,432	15,203	(16,413)
With Fuel-Related Market Response					
No EIR/RER	0	3,314	68	(80)	920
No RER	0	(2,448,623)	20,954	11,281	(4,907)
No Incremental Oil under ESI					
No Incremental Oil under ESI	0	(1,326,266)	645	(1,185)	(2,183)

Table 48. Scenarios Evaluating Changes in Market or System Conditions - System Reliability, Extended Case

	System Reliability (Change)				
Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Extended Case					
Central Case	0	(943,020)	32,663	14,022	(7,527)
No Fuel-Related Market Response					
RER Plus	0	(943,020)	32,663	14,017	(7,527)
Strike Plus $10	0	(943,020)	32,663	14,022	(7,527)
With Fuel-Related Market Response					
No EIR/RER	0	0	0	45	0
No RER	0	(860,078)	35,039	11,597	(7,585)
No Incremental Oil under ESI					
No Incremental Oil under ESI	0	(739,566)	3,017	(90)	(247)

Table 49. Scenarios Evaluating Changes in Market or System Conditions - System Reliability, Infrequent Case

	System Reliability (Change)				
Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Infrequent Case					
Central Case	0	NA	6,753	11,656	(77)
No Fuel-Related Market Response					
RER Plus	0	NA	6,753	11,656	(77)
Strike Plus $10	0	NA	6,753	11,656	(77)
With Fuel-Related Market Response					
No EIR/RER	0	NA	0	0	0
No RER	0	NA	5,896	6,609	(416)
No Incremental Oil under ESI					
No Incremental Oil under ESI	0	NA	0	0	(0)

4. Non-Winter Scenarios

Two non-Winter Scenarios evaluate changes in the ESI design, with one assuming no RER product and the other assuming a strike price set $10 per MWh above the expected RT prices for that hours. Compared to the Central Case, both Scenarios results in lower total payments. With no RER, total payments are $48 and $56 million in the Moderate and Severe Cases, respectively. These payments are $41 and $69 million lower than the corresponding payments in the Central Case. These reductions are driven in roughly equal proportion by lower FER payments and reduced net payments for DA energy options.

Increasing the strike price by $10 per MWh also results in lower payments. Compared to the Central Case, both Scenarios results in lower total payments. With no RER, total payments are $70 and $107 million in the Moderate and Severe Cases, respectively. These payments are $19 and $18 million lower than the corresponding payments in the Central Case. These reductions occurs mostly from smaller net payments for DA energy options, which are $15 and $14 million lower in the Moderate and Severe Cases, respectively.

Table 50. Non-Winter Scenarios - LMPs & Payments, Severe Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Severe Case						
Central Case	($0.23)	$1.12	$7.80	$78	$47	$125
Severe Case - ESI Design Scenario						
Strike Price Plus $10	($0.22)	$1.06	$4.74	$74	$33	$107
No RER	($0.26)	$0.82	$6.21	$47	$8	$56

Table 51. Non-Winter Scenarios - LMPs & Payments, Moderate Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Moderate Case						
Central Case	($0.18)	$0.76	$6.35	$50	$38	$89
Moderate Case - ESI Design Scenario						
Strike Price Plus $10	($0.14)	$0.68	$3.37	$47	$23	$70
No RER	($0.22)	$0.59	$5.67	$31	$16	$48

D. Conclusions Regarding Energy Security Improvements Impacts

The results of the Scenario analysis are generally consistent with and support the conclusions developed in the more detailed review of the Central Case. ESI would be expected to increase incentives for resources to maintain more secure energy supplies and generally improve their ability to deliver energy supplies in real-time. Increases in incremental fuel inventory would drive improvements in fuel system operational outcomes that are indicative of improved reliability.

ESI would be expected to increase aggregate payments by load (to suppliers) during periods when stressed market conditions are uncommon or infrequent (as indicated by winter Infrequent Case results of non-winter Moderate Case results). However, under stressed market conditions, total payments by load (to suppliers) could increase or decrease depending on a number of factors, including the nature of the stressed market conditions and amount of incremental energy inventory incented by ESI.

Under some market conditions, these incentives and payment impacts become more sensitive to market conditions, including aggregate fuel market supplies and the response of market participants to improve real-time energy deliverability.

V. Appendices

A. Additional Production Cost Model Details

1. *Mathematical Optimizer Specification*

This section summarizes the market-clearing mechanisms as implemented within the production cost model. It provides a mathematical description of the design of the day-ahead (DA) market under current market rules (CMR) and under the proposed Energy Security Improvements (ESI), and the real-time (RT) market.

a) General notation

<u>Indices</u>

i: participant

t: hour

<u>Continuous variables</u>

$g_{i,t}$: DA energy supply, including physical and virtual supply

$d_{i,t}$: DA bid-in demand, including physical and virtual demand

$r_{i,t}^{Reserve10}, r_{i,t}^{Reserve30}$: operating reserves 10 and 30-minute supply

D_t: RT cleared demand (based on scaled historical data)

<u>Parameters</u>

$c_{i,t}(\cdot)$: DA energy offer

$b_{j,t}(\cdot)$: DA demand bid

b) Model-specific notation

<u>Continuous variables</u>

$o_{i,t}^{EIR}$: EIR option quantity

$o_{i,t}^{GCR10}, o_{i,t}^{GCR30}$: GCR10, GCR30 option quantities

$o_{i,t}^{RER}$: RER option quantity

<u>Parameters</u>

L_t^{DA}: load forecast

$c_{i,t}^{EIR}(\cdot)$: EIR option offer

$c_{i,t}^{GCR10}(\cdot), c_{i,t}^{GCR30}(\cdot)$: GCR10 and GCR30 option offers

$Req_t^{GCR10}, Req_t^{GCR30}$: GCR10 and GCR30 option requirements

$c_{i,t}^{RER}(\cdot)$: RER option offers

Req_t^{RER}: RER option requirements

$Req_t^{Reserve10}, Req_t^{Reserve30}$: operating reserve 10 and 30 minute requirements

c) Market Price and Equilibrium under ESI

Market prices:[45]

- **DA LMP =** λ_t^{DA}, paid to physical and virtual supply
- **EIR/FER price =** γ_t, paid to physical supply, including physical energy supply and physical supply providing DA energy options for EIR, but not energy
- **GRC10, GCR30, RER prices =** τ_t^*, paid to generators supplying DA energy option for GCR or RER
- **RT LMP =** λ_t^{RT}, paid to generators
- **RT Operating Reserve prices =** $\tau_t^{Reserve*}$, paid to generators supplying reserves, but not energy; paid by RT load

d) Current Day-Ahead Market (CMR)

Objective function

$$\min \sum_i \sum_t \left[c_{i,t}(g_{i,t}) - b_{i,t}(d_{i,t})\right]$$

Constraints

1. DA financial energy balance constraint: For all t,

$$\sum_i (g_{i,t} - d_{i,t}) = 0 \qquad (\lambda_t^{DA} \text{ free})$$

2. DA financial capability constraint (physical generators): For all i, t,

$$g_{i,t} \le EcoMax_i \qquad (\alpha_{i,t}^{total} \ge 0)$$

e) Proposed Day-Ahead Market with ESI

ESI imposes three constraints: an EIR requirement to ensure that physical generators can satisfy the hourly DA load forecast (which may be greater than cleared supply), GCR requirements to ensure generators can satisfy RT operating reserves, and an RER requirement to ensure generators have sufficient energy to cover a large, unexpected contingency.

Objective function

$$\min \sum_i \sum_t \left[c_{i,t}(g_{i,t}) - b_{i,t}(d_{i,t}) + c_{i,t}^{EIR}(o_{i,t}^{EIR}) + c_{i,t}^{GCR10}(o_{i,t}^{GCR10}) + c_{i,t}^{GCR30}(o_{i,t}^{GCR30}) + c_{i,t}^{RER}(o_{i,t}^{RER})\right]$$

[45] We only specify which types of resources receive each type of payment (price), recognizing that there are corresponding differences in payments made by different types of resources. However, as the analysis will only consider aggregate payments by load to physical supply, we do not analyze cost allocation across different load serving entities.

Constraints

1. DA financial energy balance constraint: For all t,

   A. $\sum_i (g_{i,t} - d_{i,t}) = 0$ $\quad (\lambda_t^{DA}$ free)

2. EIR constraints: for all t,

   $\sum_i g_{i,t} + \sum_i o_{i,t}^{EIR} \geq L_t^{DA}$ $\quad (\gamma_t \geq 0, \text{free})$

3. GCR and RER constraint: for all t,

   $\sum_i o_{i,t}^{GCR10} \geq Req_t^{GCR10}$ $\quad (\tau_t^{GCR10} \geq 0, \text{free})$

   $\sum_i (o_{i,t}^{GCR10} + o_{i,t}^{GCR30}) \geq Req_t^{GCR30}$ $\quad (\tau_t^{GCR30} \geq 0, \text{free})$

   $\sum_i (o_{i,t}^{GCR10} + o_{i,t}^{GCR30} + o_{i,t}^{RER}) \geq Req_t^{RER}$ $\quad (\tau_t^{RER} \geq 0, , \text{free})$

f)Real-Time Market

Objective function

$$\min \sum_i \sum_t [c_{i,t}(g_{i,t})]$$

Constraints

1. DA financial energy balance constraint: For all t,

   B. $\sum_i (g_{i,t}) = D_T$ $\quad (\lambda_t^{RT}$ free)

2. RT Operating Reserve constraint: for all t,

   $\sum_i r_{i,t}^{Reserve10} \geq Req_t^{Reserve10}$ $\quad (\tau_t^{Reserve10} \geq 0, \text{free})$

   $\sum_i (r_{i,t}^{Reserve10} + r_{i,t}^{Reserve30}) \geq Req_t^{Reserve30}$ $\quad (\tau_t^{Reserve30} \geq 0, \text{free})$

2. Opportunity Cost Adder

Opportunity costs reflect foregone revenues of providing energy today rather than the future for resources with limited fuel inventories. As of December 2018, ISO-NE allows resources to include an adjustment to supply bids to account for opportunity costs. Opportunity cost bid adders are determined for oil-fired resources in order to maximize an oil resource's likelihood of providing energy during its most profitable hours over a 3-day period, as described below.

First, LMPs are forecasted over a 3-day period by solving a 3-day ahead market. Each oil resource is assumed to begin the 3-day period with a full tank. This provides a conservative (smaller) estimate of the opportunity costs compared to an estimate based on a longer time period. Second, oil resources determine their projected net revenues in each hour over the 3 day period based on expected LMPs and their marginal costs. Third, oil units determine their opportunity cost bid adder such that they would only provide energy during the most profitable hours given expected LMPs.

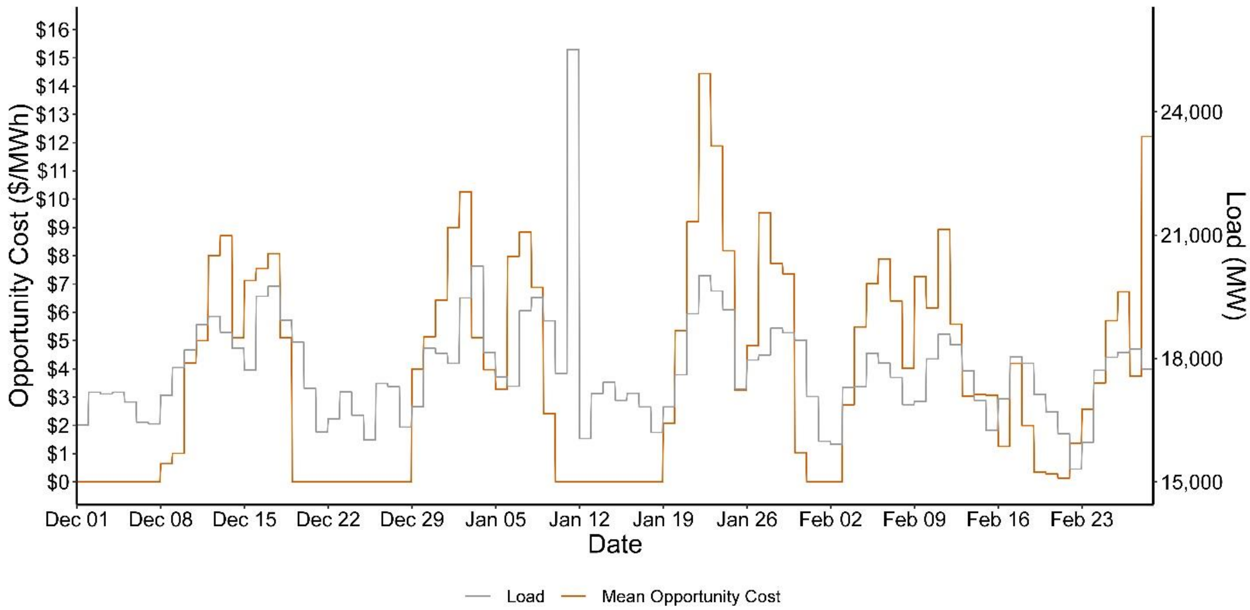
In the illustrative example shown in **Table 52**, an oil resource ranks each hour of expected net revenues from highest to lowest. If this oil resource currently has 9 hours of oil inventory, the resource will set its opportunity cost bid adder equal to the net revenues in its 10th most profitable hour, or $9.04/MWh. This opportunity cost bid adder ensures that the oil resource would only provide energy during the 9 most profitable hours.

Table 52. Illustrative Oil Hourly Net Revenue

Hour	Bid ($/MWh) [A]	Expected LMP ($/MWh) [B]	Expected Net Revenues ($/MWh) [C]=[B]-[A]	Expected Net Revenues (Rank)
41	$100.69	$117.11	$16.42	1
42	$100.69	$116.46	$15.77	2
43	$100.69	$116.42	$15.73	3
8	$100.69	$115.75	$15.06	4
9	$100.69	$115.43	$14.74	5
40	$100.69	$115.31	$14.62	6
7	$100.69	$114.58	$13.89	7
10	$100.69	$113.20	$12.51	8
11	$100.69	$111.34	$10.65	9
12	**$100.69**	**$109.73**	**$9.04**	**10**
18	$100.69	$108.34	$7.65	11
19	$100.69	$107.98	$7.29	12
37	$100.69	$104.55	$3.86	13
36	$100.69	$104.04	$3.35	14

During periods when oil-fired resources are unprofitable (non-competitive) or have large oil inventories, oil-fired resources will have no opportunity costs. Positive opportunity costs tend to occur during periods with high load, high natural gas prices, and limited fuel inventories (e.g., after a prior cold spell). **Figure 29** shows the relationship between daily peak load and opportunity costs for the Frequent Case. Positive opportunity costs tend to overlap with periods of high daily peak loads and increase in magnitude (relative to load) as oil inventories are depleted throughout the winter. Opportunity costs can cause shifts in the timing of supply from energy-limited resources, causing them to supply energy at a later point in time than they otherwise would have without opportunity costs.

Figure 29: Day-Ahead Daily Peak Load and Opportunity Costs - Frequent Case



3. Demand Bid Calibration

The demand curves used within the PCM are constructed hourly for the DA market based on historical bids from the relevant historical period for a given scenario. Demand curves are constructed in four stages:

First, historical physical demand, virtual demand (DECs) and virtual supply (INCs) are separated into price buckets and netted against each other to create an aggregate, stepped demand curve.

Second, historical bid quantities are scaled to account for the difference between historical and projected future load levels. An hourly future load quantity is first calculated based on the 2019 CELT forecast peak and total energy (see Section III.B.1). Then, historical bid quantities are scaled by the ratio of future load quantities to historic load quantities.

Third, historical demand bid prices are scaled to future DA LMPs as estimated by the PCM. These changes are driven from a variety of factors, such as assumptions regarding the resource fleet. Future DA LMPs are first calculated by running a version of the DA market with fixed hourly future loads and current market rules (no ESI products). Demand bid prices are then scaled by the ratio of these calculated future DA LMPs to historical DA LMPs.

A fourth step is used only in cases modeling EIR. This step accounts for arbitrage opportunities between DA and RT LMPs. As described in SectionIII.B.5, all else equal, DA LMPs will tend to be lower under ESI due to the substitutions between DA energy and EIR. This would lead to divergence between DA and RT LMPs, introducing an arbitrage opportunity. To capture the market's response to this opportunity, demand is increased (i.e., demand curves are shifted to the right) under ESI so that DA LMPs align with expected RT LMPs.

B. Resource Data and Assumptions

This section details the data sources, model assumptions, and methodology used to evaluate the impacts of ESI on energy market outcomes.

1. Electricity Market

Energy suppliers are modeled either as individual (discrete) resources to be optimized by the production cost model, or profiles that are netted off from load, reserve, or DA energy option requirements. This section outlines how the resource characteristics and supply amounts (for profiled resources) are determined.

a) Central Case Resources and Retirements

The electricity supply for Winter (2025-26) and Non-Winter (2026) Cases includes all generators that cleared ISO-NE's thirteenth Forward Capacity Auction (FCA 13) on February 4, 2019 for the Capacity Commitment Period of June 1, 2022 to May 31, 2023. These resources are carried forward into future scenarios unless otherwise removed for scenario-specific testing. In addition to these FCA-cleared units, future supply includes 886 MW of new solar capability, 458 MW of battery storage, and 1,339 MW of wind capability (507 MW onshore, 832 MW offshore.[46] These additions are based on the 10-year projections in ISO-NE's 2019 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT 2019).[47] **Table 4** in the body of this report shows electricity capacity assumptions by resource type under current market rules and ESI.[48]

We assume a number of resource retirements for all scenarios based on the FCA 13 retirement delist offers in addition to specifications from ISO-NE.[49] We also assume the retirement of Mystic 8 and 9 in addition to resources that have announced retirements.

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[46] New capacity from Generator List with Existing and Expected Seasonal Claimed Capability, S&P Global Market Intelligence. Additional capacity is compared with existing capacity in August 2019. Offshore generation capability derived from nameplate capacity and historical generation values from Vineyard Wind.

[47] ISO New England. (2018, September 5). 2018-2027 Forecast Report of Capacity, Energy, Loads and Transmission. Retrieved from https://www.iso-ne.com/system-planning/system-plans-studies/celt/ (ISO New England, 2018)

[48] Under ESI, electricity supply also includes 616 MW sourced from liquefied natural gas.

[49] Correspondence with ISO New England Staff.

Table 53. Assumed Retirements

Resource	Non-Winter Capacity (MW)	Winter Capacity (MW)
Gas Combined Cycle	1,413	1,700
Nuclear Steam	677	683
Gas/Oil Steam	575	560
Coal Steam	383	385
Gas/Oil Combined Cycle	54	57
Oil Combustion (Gas) Turbine	30	41
Bio/Refuse	11	16
Hydro (Daily Cycle - Run Of River)	4	10
Oil Internal Combustion	8	8
Hydro (Weekly Cycle)	2	2
Total	**3,158**	**3,464**

b) Discretely Modeled Resource Characteristics

Optimized resources include coal, dual-fuel, fuel cell, gas-only, oil-only, nuclear, biomass and refuse, price responsive demand (active demand response), and imports. Biomass, price responsive demand, and imports are modeled as aggregated units. All other resource types are modeled as individual units based on unit-specific ISO-NE and SNL data.

Individual resources are modeled based on unit-specific characteristics, including capacity, heat rate, emissions rates, variable costs, and fuel storage capabilities. These capabilities are used within the Production Cost Model to optimize total production cost and meet reserve requirements over the modeling periods. Unit-level characteristics are specific to each modeled generating unit and do not vary across hours but do vary seasonally in the winter, summer, and shoulder seasons based on expected capacity and outage rates.

Unit capacity is based on the Winter SCC in the Winter and Expected Summer Peak SCC in the Non-Winter. EFORd is modeled as a percentage decrement in capacity (in all hours) and based on plant specific seasonal EFORd rates in the Winter and Summer (June 1st to August 31st). In the Shoulder season (March 1st to May 31st and October 1st to November 30th), the outage rate is based on a fleet average of 18% and is applied to all plants equally.[50] Heat rate, allowance costs, non-fuel variable O&M costs, and non-fuel non-allowance variable O&M costs are taken from SNL, or, when missing, averaged by fuel type for dispatchable units.

[50] In September, the outage rate is based on a fleet average for September of 12% and is applied equally as well. This month was split apart to adjust more readily for historically high loads in this month, during which resources would have been less likely to undergo unforced maintenance. For shoulder seasons, the outage rate was based on the publically available information in ISONE's morning report. This outage rate is "the sum of capability of all generation scheduled Out of Service (OOS), forced OOS, or reduced for the day, as known at the time of Morning Report development for the peak hour of the day," available under "Generation Outages and Reductions" at https://www.iso-ne.com/markets-operations/system-forecast-status/morning-report/.

i) *Biomass and Price Responsive Demand*

Biomass and refuse quantity and offers (i.e., marginal costs) are modeled in segments based on historical generation and day-ahead offers from wood and municipal solid waste plants for winters 2013-2014 through 2017-2018. The historical MW offers were used to generate a supply curve for plants.

ISO-NE implemented Price Responsive Demand (PRD) effective July 1, 2018. PRD quantity and offers are modeled in three segments based on historical day-ahead offers.

ii) *Imports*

Imports are modeled as individual generating units similar to biomass and active demand response with prices dependent on capacity. The model includes the following interconnections: Northport-Norwalk (Northpoint connection point), Cross-Sound Cable (Salisbury connection point), New York-New England Northern AC (Roseton and Shoreham connection points), and Hydro Quebec Phase I/II. Offers and capacity were determined using hourly transaction data from ISO-NE beginning June 1, 2012 and ending May 31, 2018. Import offers for all interconnections, excluding Roseton, are set at the mean of observed real-time hourly imports in MW. Import offers for Roseton are the mean of real-time hourly imports segmented by $20/MWh price bins between $0 and $100/MWh. The Roseton price bins reflect a supply curve observed in the historical data. Hourly data for Northport-Norwalk, Cross-Sound Cable, Hydro Quebec Phase I/II, and the Shoreham connection point of New York-New England Northern AC did not show meaningful price-supply relationships.

c) Hourly Profiled Resource Characteristics

i) *Solar, Wind, and Hydroelectric*

Unit characteristics for solar, wind, and hydroelectric power are derived from the generator list reported in CELT 2019 and cleared in FCA 13.[51] Future hourly generation for renewable and hydroelectric units is based on historical hourly generation in the winter or non-winter scenario and scaled by the historical capacity's share of the assumed future capacity. Scaled resources include on-shore wind, photovoltaic solar, run-of-river, and pondage hydroelectric power. Hourly power generation is based on historical data received from ISO-NE.

ii) *Pumped Storage and Battery Storage*

Future generation for pumped storage units is based on a 24-hour generation profile received from ISO-NE that is scaled proportionally to capacity in each hour. The storage profiles model pumping or charging as extra demand. To model round-trip efficiency for storage units, energy consumed during pumping or charging exceeds energy produced.

[51] ISO New England. (2018, September 5). 2018-2027 Forecast Report of Capacity, Energy, Loads and Transmission. Retrieved from https://www.iso-ne.com/system-planning/system-plans-studies/celt/

iii) Off-Shore Wind

Unit characteristics for off-shore wind are derived from modeled hourly generation data received from ISO-NE that is based upon offshore meteorological buoy wind speed data.

d) Real-Time Reserve Provision

Real-time operating reserves are modeled for 10-minute and 30-minute operating reserve products. We do not model separate spin and non-spin 10-minute reserves, but rather model a single 10-minute product.

Offline reserve capabilities are based on historical analysis of Claim 10 and Claim 30 audit data. Claim 10 and Claim 30 capabilities for dispatchable generation (oil, gas, coal, and dual-fuel) are based on the weekly Claim 10 and Claim 30 Capability report generated by ISO-NE over the period December 1, 2018 through February 28, 2019. Offline reserve capabilities are constant over a winter. For the non-winter period, the offline reserve capability is calculated between March 1, 2019 and October 1, 2019.

Dispatchable hydroelectric power reserve capabilities are profiled from hourly averages of five-minute data from June 1, 2012 through December 31, 2018 on ten-minute operating reserves, ten-minute spinning reserves, and thirty-minute spinning reserves. The future reserve profile for hydroelectric units is based on the hourly data in the specific winter or non-winter scenario and scaled by the historical capacity's share of the assumed future capacity.

e) Day-Ahead Energy Option Provision

The model assumes that oil, gas, dual-fuel, coal, run of river hydro, weekly hydro, pond hydro, and pumped storage are able to provide day-ahead energy options. For resources not modeled as profiles (as explained in Section V.B.1.b. above), resources provide GCR10, GCR30, EIR, and RER240 based on measures of offline reserve capability (for resources supplying from a cold start) or ramp capability (for resources that must be on-line to supply reserves).

Resources able to provide day-ahead energy options from a cold start are combustion turbines and internal combustion engines. GCR10 and GCR30 capabilities are based on historical Claim 10 and Claim 30 data provided by ISO-NE. EIR and RER240 capabilities are based on modeled Claim 60 (for EIR) and Claim 240 (for RER) values modeled and provided by ISO-NE.[52]

Resources able to provide day-ahead energy options only when also providing energy are combined cycle, steam, and coal units. These units must be supplying energy in order to be cleared by the production cost model for day-ahead energy options. The capability of these resources to provide day-ahead energy options are based on ramp rate data provided from ISO-NE.

Resources that are modeled as profiles can provide GCR10, GCR30 or RER240 based on historic levels of real-time operating reserves (see Section V.B.1.c., above). Resources are assumed to provide day-ahead

52 For more information, see Ewing, Ben, "Energy Security Improvements: Market-Based Approaches," January 13-15, 2020. https://www.iso-ne.com/static-assets/documents/2020/01/a5_a_iii_esi_replacement_energy_reserves_rev1.pptx.

energy options in equivalent quantities to historic operating reserve levels. Generally, these resources provide GCR10 and GCR30. In some rare hours, where historic operating reserves exceed the GCR requirements, these resources are modeled to provide RER.

2. Fuel and Emission Prices

a) Natural Gas

Projected natural gas prices take Algonquin City Gate daily spot prices from winters 2013-14, 2016-17, and 2017-18 in dollars per million btu[53] While the model forecasts hourly gas constraints using historical inventory and deviation from heating degree day, projected gas prices are unadjusted from the daily base year price and are constant over the 24 hours of a gas-day. **Figure 30** shows the prices for natural gas and other fuels used in the winter months, while **Figure 31** shows these prices for the non-winter months.

b) LNG

Natural gas units with a forward LNG contracts exercise calls on these supplies when the Algonquin spot price exceeds a trigger price, set to $16 per MMBtu. When exercised, these supplies have a production cost of $10 per MMBtu, which is the commodity price under the assumed contract. The trigger price exceeds the commodity price to account for the opportunity cost of each call, as the contract only provides for 10 days of supply and exercising calls when prices are too low would limit the opportunity to exercise on days when the price could be higher.

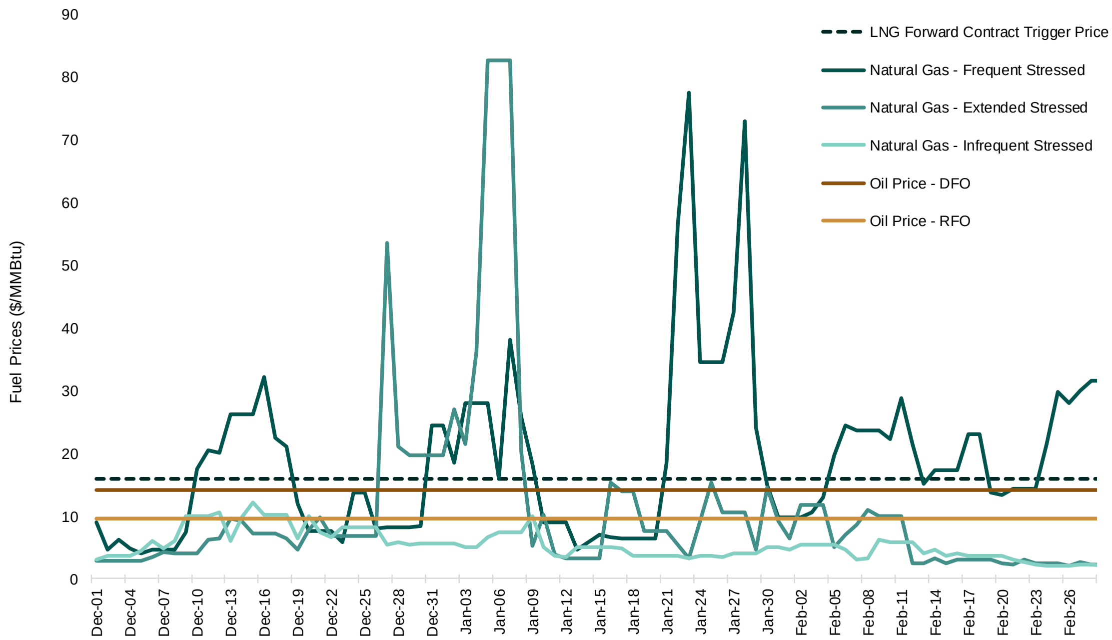
c) Oil

Units which use oil for their primary or secondary fuel may use 1) distillate fuel oil (DFO), 2) residual fuel oil (RFO), 3) jet fuel, or 4) kerosene. Forecasted prices use the December 2021 futures prices for each oil type: New York Harbor Heating Oil Futures NYMEX, New York Harbor Residual Fuel Oil 1.0% Sulfur futures, and Gulf Coast Jet Fuel (Platts) Futures Quotes for jet fuel and kerosene.[54] These oil prices do not vary over a season or by hour, the two time points at which the model differentiates across units. Figures 3a and 3b show fuel prices for natural gas over the three winter severities and two non-winter severities, the LNG contract trigger price, and DFO and RFO oil.

[53] Source data year depends on winter severity. Algonquin City Gate prices from S&P Global Market Intelligence.

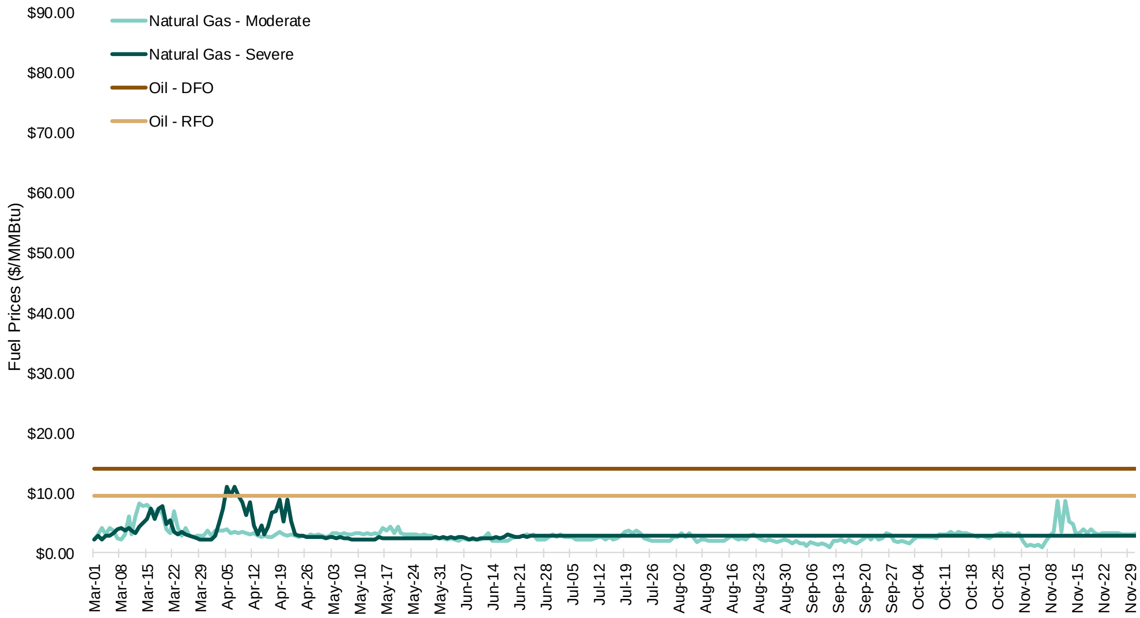
[54] December 2021 was selected due to observed trading activity and market liquidity.

Figure 30: Future Fuel Prices by Winter Severity ($/MMBtu)[55]



55 The Algonquin Natural Gas Price series is based on 2013/14, 2016/17, and 2017/18 prices for frequent, infrequent, and extended stressed conditions, respectively. The LNG Forward Contract Trigger Price is $16/MMBtu, which indicates a resource would exercise the LNG Forward Contract whenever the price of Natural Gas rises above $16/MMBtu. The modeled LNG contract is a forward contract with 10 calls, where one call is reserved to supply DA energy options. The commodity charge under an LNG Forward Contracts is $10/MMbtu. The DFO - Oil price is $14.06/MMBtu ($81.27/BBL), based on December 2021 Futures. The RFO - Oil price is $9.64/MMBtu ($60.58/BBL), based on December 2021 Futures.

Figure 31: Future Fuel Prices by Non-Winter Severity ($/MMBtu)[56]



d) Coal

Coal prices are quarterly and based on shipments to the electric power sector by state from the Energy Intelligence Agency.[57]

e) Emissions

Emission costs includes costs per ton of emitted CO_2, SO_2, and NOx. The CO_2 emissions price for each fuel type is the clearing price from the Regional Greenhouse Gas Initiative of New England and Mid-Atlantic States of the US (RGGI) 43rd auction held on March 13, 2019.[58] We do not model allowance prices, holdings, or acquisitions and do not distinguish by "regulated entities." All units are assumed to take the RGGI price as the price for their CO_2 emissions. Emissions prices for SO_2 are derived from annual allowances of SO_2 acid rain and take the May 2019 forward price for winter and non-winter months.[59] Emissions prices for NOx are derived

[56] The Algonquin Natural Gas Price series is based 2017 and 2018 prices moderate and severe non-winter conditions, respectively. The LNG Forward Contract Trigger Price is $16/MMBtu, which indicates a resource would exercise the LNG Forward Contract whenever the price of Natural Gas rises above $16/MMBtu. The modeled LNG contract is a forward contract with 10 calls, where one call is reserved to supply DA energy options. The commodity charge under an LNG Forward Contracts is $10/MMbtu. The DFO - Oil price is $14.06/MMBtu ($81.27/BBL), based on December 2021 Futures. The RFO - Oil price is $9.64/MMBtu ($60.58/BBL), based on December 2021 Futures.

[57] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis. Retrieved from https://www.eia.gov/coal/data/browser/#/topic/45?agg=1,0&geo=8&rank=g&freq=Q&rtype=s&pin=&rse=0&maptype=0&ltype=pin&ctype=map&end=201802&start=200801

[58] Elements of RGGI. Retrieved from https://www.rggi.org/program-overview-and-design/elements

[59] S&P Global Market Intelligence for Acid Rain Annual SO2 Allowances.

from annual allowances from the US Environmental Protection Agency Cross-State Air Pollution Rules and take the May 2019 forward price for winter and non-winter months.[60]

3. *Oil Starting Inventory, Oil Holding Costs, and LNG Contracting*

a) Oil Starting Storage

Resources that use oil for their primary or secondary fuel have additional characteristics related to fuel storage, consumption, and replenishment rates. These refueling characteristic assumptions are based on periodic oil resource survey data from August 2014 through April 30, 2019, received from ISO-NE. Under CMR, historic inventory levels were used.

This section describes our assumptions of each resource's starting storage under CMR and ESI.

i) Initial Inventory under Current Market Rules

Each resource's projected starting storage under current market rules is based on the 2018-2019 average inventory as of December 1st.

ii) Initial Inventory under ESI

Each resource's average December inventory over the period 2014 to 2016 is used as a starting point for determining the quantity of fuel assumed under ESI. From this starting point, adjustments were made to reflect multiple factors associated with the benefits of incremental storage, relative to CMR levels:

1. For a subset of resources with at least seven days of storage, initial inventory is set to their CMR (December 2018) initial inventory level. Analysis found that further increasing initial inventories for these resources beyond 7-days of fuel provided little economic value, potentially imposing holding costs in excess of additional revenues.
2. For resources with smaller tank sizes (no more than three days of storage and refueled by truck) and inventories at low levels over the period 2014 to 2016, initial inventories are set, at a minimum, to 70 percent of their maximum storage. These resources accrue sufficient energy option revenues and FER payments to compensate their incremental oil holding costs.
3. The most-efficient (low heat rate) resources are assumed to hold larger initial inventories, set at 5% or 10% above average December 2014-16 inventories depending on the level of efficiency.
4. The most-inefficient (high heat rate) resources are assumed to hold smaller initial inventories, set at the mid-point between the average December 2014-16 inventories and the average December 2018 inventory (i.e., the level assumed under CMR).

[60] S&P Global Market Intelligence for Annual Cross-State Air Pollution (CSAPR) NOx Allowances.

Resources that refuel their oil inventory via pipeline are assumed to refuel oil as often as is required to supply energy under both CMR and ESI.

b) Oil Holding Costs

Storing oil imposes an economic costs, referred to as a "holding cost." If a resource procures stored fuel oil, there is risk that this fuel is not consumed during the winter season, and the resource is still holding the fuel at the end of the winter. We measure the cost associated with holding oil such quantities of oil at the end of a winter season. We model holding costs as the combination of three costs faced by any resource that purchases oil: fuel carrying cost, price risk, and liquidity risk.

- **Carrying Cost**: carrying cost reflects the opportunity cost of purchasing oil and storing it for a period of time in a tank rather *than* using the capital in another way. The risk free component of a resource's weighted average cost of capital (WACC) represents this opportunity cost of funds.
- **Liquidity Risk**: once purchased, fuel-oil can be difficult to re-sell. Being left with oil in the tank at the end of a winter season therefore ties up valuable assets for the resource until the next winter season. This liquidity risk can be represented as a risk premium on top of the risk-free opportunity cost of capital, or simply the difference between a resource's WACC and the risk-free rate (often represented by T-bills). Thus, taken together, the carrying cost and liquidity risk can be represented by a resource's WACC.
- **Price Risk**: price risk refers to the risk a resource faces of the price of oil falling below the original purchase price before the end of the storage period (e.g. the end of the winter season). If the price of oil falls below its original purchase price, the resource will be left with a depreciated asset. The price of a "put option"—a financial instrument that offers the purchaser of the option the opportunity to sell the product (in this case oil) at a pre-determined price—reflects the value of this price risk.

The combination of carrying cost, liquidity risk, and price risk represent an upper bound on the holding costs a resource may incur. We estimate holding costs in dollars per megawatt-hour [$/MWh] for each generating unit based on the amount of fuel it has remaining at the end of the Winter model run. Specifically, for each unit, we calculate the following relationship:

Holding cost ($/MWh) = holding cost ($/BBL) ÷ fuel energy content (MMBtu/BBL) ×
unit heat rate (Btu/kWh/1000)

Where the components are defined as:

- *holding cost ($/BBL)*: the combination of carrying cost, liquidity risk, and price risk for units combusting residual fuel oil (RFO) and distillate fuel oil (DFO). Drawing from past work, we estimate carrying cost and liquidity risk as the WACC of the price of RFO or DFO in $/BBL.[61] To represent price risk, we draw from past work that estimated a fuel specific premium payment on a put option. We illustrate our assumptions in the table below:

Table 54: Fuel Holding Costs ($/BBL)

	Fuel Price	WACC	Put Option	Holding Cost
	[A]	[B]	[C]	[D] = [A]×[B] + [C]
RFO	$88.30 / BBL	8%	$6.14	$13.20 / BBL
DFO	$89.54 / BBL	8%	$8.46	$15.62 / BBL

- *fuel energy content (MMBtu/BBL)*: RFO and DFO contain different energy contents per barrel of fuel. Specifically, RFO contains 6.287 MMBtu/BBL and DFO contains 5.817 MMBtu/BBL.[62]
- *unit heat rate (Btu/kWh)*: We derive unit specific heat rates from SNL Financial. SNL reports values in Btu/kWh. To convert to MMBtu / MWh, we divide by 1,000.[63]

c) Natural Gas Modeling

In winter months under CMR and in non-winter months, we assume no forward LNG contracting. However, under ESI, we assume that market participants would enter into forward contracts with LNG terminals that provide supplies of natural gas. The total capacity of natural gas available for forward contracting was determined through an analysis of various demands on LNG terminal capability during the future modelled year, 2025/26. This analysis considers the capacity available from the LNG terminals, as the terminals would not be expected to sign contracts for supplies that exceed the capacity they can deliver on each day. This analysis is shown in **Table 55**.

First, we estimate the amount of LNG that would be needed to meet LDC demand on a "design day" was determined. These LNG supplies are needed by LDCs to ensure they can meet peak demand on a "design day," the hypothetical day in which the LDCs are expected to put the greatest demand on the gas system. LDC design day needs are estimated to be 0.71 Bcf/day

Second, we determined available natural gas supply from the LNG terminals. With the assumed retirement of DOMAC, supplies are assumed to be provided by Canaport, as limited by pipeline capability. Potential natural gas supply capacity from the LNG terminals is estimated to be 0.833 Bcf/day.

61 Hibbard, Paul and Todd Schatzki, "Further Explanation on Rate Calculations," May 28, 2014. https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/jun32014/a02a_analysis_group_memo_05_28_14.pdf

62 "Energy Units and Calculators, Explained," U.S. Energy Information Administration, https://www.eia.gov/energyexplained/index.php?page=about_energy_units.

63 (Btu / kWh) × (1000 kWh / 1 MWh) × (1 MMBtu / 1,000,000 Btu) = MMBtu / 1,000 MWh.

Third, deliverable natural gas capacity for the electricity sector was calculated as the difference between potential capacity from the LNG terminals and LDC design day demand. The amount is 0.12 Bcf/day. Thus we assume that forward contracts for this amount of fuel would be available to the electric power sector.

Table 55. Quantity Available for LNG Forward Contracting[64]

			Source
LDC Design Day Temperature (EDD)	[A]	75	Assumption
Pipeline Import Capacity (Bcf/day)	[B]	3.59	FCA 14 presentation
LDC Demand on Design Day (Bcf/day, ISO Model)	[C]	5.76	ISO NE model
Satellite LNG Injection Quantity on Design Day (Bcf/day, ISO Model)	[D]	1.46	ISO NE model, capped at 1.456 Bcf/day
LDC Design Day Demand to be met by LNG (Bcf/day)	[E]=[C]-[B]-[D]	**0.71**	
Assuming LDCs contract LDC Design Day Demand as firm capacity with LNG terminals…			
Canaport LNG Terminal Capacity (Bcf/day)	[F]	1.20	OFSA
M&N Pipeline Capacity (Bcf/day)	[G]	0.833	OFSA
Canaport Deliverable Capacity (Bcf/day)	[H]= Min([F],[G])	0.833	OFSA
Total LNG Capacity without DOMAC (Bcf/day)	[I]=[H]	**0.833**	Calculation
Total LNG Capacity Available for LNG Forward Contracting without DOMAC (Bcf/day)	[J]=[I]-[E]	**0.12**	
Total LNG Capacity Available for LNG Forward Contracting without DOMAC (MMBtu/hr)	[K] = [J] converted	**5,313**	
Total Gas-only Capacity assumed with LNG forward contracts (SCC MW)	[L]	**616**	Based on most efficient gas-only units
Percentage of LNG reserved for Design Day Demand available for electrical generators		**100%**	

The forward LNG contract was assigned to the more efficient combined cycle gas-only resources. We assume that the forward contract would have 10 call options over the 90-day winter period. The modeled contract has a reservation of $13.19/MMBtu, and a strike price of $10/MMBtu.[65] This means that resources must pay $13.19/MMBtu prior to the winter to secure the contract, then will be able to purchase gas at the strike price of $10/MMBtu when exercising a call.

64 Sources are: [1] Norman Sproehnle, "Reliability Reviews for Fuel Security: Model Inputs, Results, and Criteria for Unit Retention in the Forward Capacity Market (FCM)," July 31, 2018, "a2_1_iso_presentation_reliability_reviews_for_fuel_security.pptx"; [2] ISO-NE, LDC Gas Demand model, "2018_ICF_LDC_gas_demand.xlsx" [3] ISO-NE, "Operation Fuel-Security Analysis," January 17, 2018. [4] Discussion with ISO-NE, July 10, 2019.

65 Analysis performed in the context of analysis performed for the interim inventories energy program. *See* Testimony of Todd Schatzki, Federal Energy Regulatory Commission, Docket No. ER19-1428-000.

C. Day-Ahead Energy Options Offers

ESI requires the procurement of day-ahead (DA) energy options from suppliers in the market.[66] Under ESI, market participants would submit offers reflecting their willingness to accept the obligation to settle ("closeout") at the option's pay out terms (to ISO-NE). In principle, this valuation reflects many factors, such as the expected payout, the risk associated with the option, and the resulting financial risk faced by market participants, given a potential correlation between option settlement and other revenue streams.

To estimate offer prices for DA energy options, we assume that suppliers' willingness to accept reflects expected closeout costs plus a premium to capture the financial risk associated with the uncertain closeout costs. This approach differs from the approach commonly taken to estimate the value of options traded in financial markets, which relies on constructing a replicating portfolio for the derivative. The options procured through ESI, however, cannot be replicated through a portfolio of thickly traded assets (e.g., forwards and cash positions), as is the case for many financial derivatives. Thus, valuations will reflect each market participant's expectations regarding likely costs and associated risks, potentially modified by opportunities to hedge such risks through other market products.[67] Further, the ESI design assumes that all market participants submit offers for DA energy options that reflect their underlying valuation, with the resulting market-clearing price reflecting the marginal offer given the quantity administratively procured. The resulting price will differ from the price that emerges from financial markets, where equilibrium prices reflect bi-lateral transactions between those willing to accept and willing to pay for the derivative. The finance literature does not provide unique methodologies to estimate derivative offer prices under these circumstances.

The energy option offer includes two components: the expected closeout costs and a risk premium. First, we describe the approach taken to estimating the expected closeout costs and then describe the approach taken to estimating the risk premium.

1. Expected Closeout Costs

The estimates for the expected closeout costs are based on the difference between the real-time LMP (RT LMP), and the "strike price" (K) in each hour. Resources owe a payment of $(RT\ LMP - K)$ to closeout the option, if the option is "in the money", or when $(RT\ LMP - K) > 0$. Otherwise the payout is zero. Thus, the key driver of the bidding for the ESI products is the volatility of the real-time settlement, or in other words, $max\{(RT\ LMP - K), 0\}$.

For each hour when estimating offer prices, the **strike price, *K*,** is set to be equal to the historic **day-ahead LMP** in that hour.

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[66] References for this section are: Bessimbinder, Hendrik and Michael Lemmon, "Equilibrium Pricing and Optimal Hedging in Electricity Forward Markets"; Bunn, Derek and Dipeng Chen, 2013, "The forward premium in electricity futures," Journal of Empirical Finance, 23: 173-186.; Cochrane, John and Jesus Saa-Requejo, 1999, "Beyond Arbitrage: Good-Deal Asset Price Bounds in Incomplete Markets."; and Jacobs, Kris, Yu Li, and Craig Pirrong, 2017, "Supply, Demand, and Risk Premiums in Electricity Markets."

[67] Cochrane and Saa-Requejo, 1999, consider approaches to derivative valuation that reflect "good deals" given opportunities to partially hedge a derivatives risks.

We compute the expected closeout costs through a multi-step process.

1. We use historical data provided by ISO-NE on LMPs between June 2012 and May 2019 to compute the historical time series of **real-time LMP** minus **K**.
2. We estimated fitted values for the difference in real-time LMP and strike price *(RT LMP - K)* for each hour. This fitted value provides a single, point estimate of *(RT LMP - K)*. The fitted value is estimated using the following linear model, estimated over our sample:

$$(RT\ LMP - K) = \beta_1(HDD) + \beta_2(Hour\ of\ Day) + \beta_3(Day\ of\ Week) + \beta_4(Month\ of\ Winter) + \beta_4(Winter) + \varepsilon$$

3. We calculate model residuals ε from our estimated model as the difference between the actual *(RT LMP - K)* and the fitted *(RT LMP - K)*.
4. Using a Monte Carlo method, we simulate a distribution for *(RT LMP - K)*. To create this simulated distribution for each hour, we take the fitted value and randomly draw one residual from the sample of model residuals, ε. We replicate this step 1,000 times (with replacement) to create a distribution of *(RT LMP - K)* with 1,000 values.
5. Having created the distribution of *(RT LMP - K)* with 1,000 simulated values for each hour, we then calculate the closeout costs in each simulated hour in the distribution – i.e.,$Y_i = max(LMP - K + \varepsilon_i, o)$. Having calculated the closeout cost for each hour in the distribution, we then estimate the mean of all simulated Y_i's in each hour to obtain the expected closeout costs in that hour, $\overline{Y_t}$.

Steps 3 to 6 allow us to account for the asymmetry in the closeout costs of the DA energy option. That is, because the closeout cost is the maximum of *(RT LMP - K)* and zero (i.e., $max(LMP^{RT} - K, 0)$), there is a positive closeout cost only when the RT LMP exceeds the strike price.

To illustrate this asymmetry, consider the following illustrative example show in **Table 56**. Assume that the strike price is $40 per MWh and the model estimates that *(RT LMP - K)* is $5 per MWh, implying a RT LMP of $55 per MWh. Further, assume there is a 50% probability that the RT LMP is $10 per MWh lower and a 50% probability that the RT LMP is $10 per MWh higher. This uncertainty does not change the expected value – the average of *(RT LMP - K)* is still $5 per MWh even if there is a 50% probability the price is –$5 per MWh and 50% probability the price is $15 per MWh. However, this uncertainty has an asymmetric effect on the option closeout costs, as there is a 50% probability the closeout cost is $15 per MWh and a 50% probability the closeout cost is $0 per MWh, such that the average closeout cost is $7.50 per MWh, not $5 per MWh.

Table 56. Illustrative Example of Asymmetric Effect of Uncertainty on Option Closeout

	Case Probability	Fitted Value (RT LMP - K)	Realized (RT LMP - K)	Option Closeout Cost
Case 1	50%	$5.00	-$5.00	$0.00
Case 2	50%	$5.00	$15.00	$15.00
Expected Value			$5.00	$7.50

When sampling residuals from the estimated model, we restrict the sample to residuals from that historical year. The model is fit to winter months only (December, January, and February) when estimating offer prices for the winter month analyses. For the non-winter solves, the same model is fit to each nine month period comprising the two non-winter seasons. Additionally, for the non-winter cases offers are modeled separately for each season (spring, summer, and fall), to account for seasonal differences.

2. Approach to Estimating a DA Risk Premium

The approach taken to estimating a risk premium builds off the observation that the same risk preferences underlying risk premiums for derivatives traded in electricity markets should underlie risk premiums for DA energy options.[68] Thus, while there is limited market information on energy options, electricity forwards (e.g., a DA energy) are commonly traded in electricity markets, including New England's energy markets.[69]

Our approach accounts for a number of reasonable features of the risk premiums:

1. The risk premium reflects the (magnitude of) financial risk taken on when awarded a DA energy option. Thus, all else equal, the size of the risk premium increases with the variability of LMPs. Moreover, the risk premium may increase disproportionately with the level of financial risk assumed, if market participants are disproportionately averse to large losses. Thus, there could be a non-linear (convex) relationship between the risk premium and metrics of financial risk (e.g., the variability in returns).
2. The risk premium is larger for a resource with no inventoried energy, as it faces a riskier, unhedged financial position.
3. The risk premium varies the resource's marginal cost of supplying energy, as it bounds the potential loss to (*MC* – *K*), providing a partial hedge on the DA energy option settlement risk.
4. The risk premium could be negative for resources for which the DA energy option lowers financial risk (e.g., if the resource has low *MC* relative to *K*).
5. The risk premium will depend on operational and intertemporal factors that prevent physical energy inventory from perfectly hedging financial risks.

DA energy option risk premiums are estimated using the following equation for unit *j* at time *t*:

$$r_{o,j,t} = r_f * \frac{R_t}{C_t} * \left(\frac{\sigma_{o,j}}{\sigma_f}\right)^{\gamma} * p_j$$

Where:

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68 Because the DA energy options will not be a traded product, but cleared through a market with fixed demand, and because the DA energy options are real options that cannot be replicated through existing financial markets (i.e., they are not spanned), conventional derivative pricing models are not appropriate to determining market participant bids to supply the DA energy options (e.g., see Cochrane and Saa-Requejo, 1999)

69 Prior research shows that risk premiums for day-ahead positions vary with multiple factors, particularly expected RT price variability and skewness. Observed risk premiums reflect an equilibrium outcome in which both buyers and sellers may desire to mitigate the risk of real-time energy market sales. Jacobs, Li and Pirrong (2017), for example, find that the equilibrium risk premium, reflecting both seller and buyer premiums, is 1 to 2 percent, with larger values in more volatile winter periods, while Bunn and Chen (2013) find Great Britain winter premiums are 7.2% for on-peak and 4.8% for off-peak, while summer premiums are –1.3% for on-peak and –1.0% for off-peak. We are not aware of empirical research has performed such empirical analysis for electricity options.

- $r_{o,t}$ is the option risk premium for hour t
- r_f is the average day-ahead unhedged forward risk premium for hour *t*, assumed to be 0.015 (i.e., a 1.5% risk premium)
- R_t is the (expected) real-time price, estimated as the day-ahead price for hour t
- C_t is the (expected) call option price, estimated as the expected close out cost for hour t
- σ_o, σ_f is the standard deviation of margins earned for the option for either option or forward contract, measured for peak and off-peak hours[70]
- γ allows for a non-linear relationship between RT settlement risk (variability) and risk premium, and is assumed to be 1 (i.e., no non-linear relationship is assumed, at present)
- p is a unit-specific adjustment to account for intertemporal constraints to the delivery of energy at *MC*, such as lost opportunities (revenues) due to start-up lead-time and operational risk

This formula starts with an estimate of the average day-ahead forward risk premium (in percentage terms), reflecting a range of market conditions. This risk premium is that adjusted for several factors:

- First, risk premiums are adjusted for the size of the option price relative to the forward price $\left(\frac{R_t}{C_t}\right)$.

  Within the finance literature, this is referred to as the assets delta. This adjustment accounts for the fact that an investor will require the same compensation to bear the same risk, irrespective of the instrument's price. Adjusting the risk premium for the relative prices ensure that this is the case.

- Second, the risk premium is adjusted to account for relative differences in the size of the risk, as measured by the standard deviation of the (negative) returns $\left(\frac{\sigma_{o,j}}{\sigma_f}\right)^{\gamma}$.

- Third, the risk premium is adjusted for operational risks, including intertemporal constraints. The estimated risk (variability) of returns to the DA energy option assumes that the resource always delivers energy whenever LMP^{RT} > MC. However, in practice, within the real-time market, multiple factors may limit the extent to which a resource can supply energy. The adjustment factor, *p*, accounts for these factors.

Under this approach: several of the parameters, r_f, *p*, σ_f and γ, are constant across offers; two parameters, R_t and C_t, vary by hour; and one parameter, σ_o, varies across resources. Currently, the standard deviation of the option, σ_o, is calculated for each resource in each hour as a function of $\Delta = MC - K$ for peak and off-peak periods. Estimates of σ_o are based on the following function for peak and off-peak hours ($h = \{peak, offpeak\}$):

$$\sigma_o = \beta_{0,h} + \beta_{1,h}\sqrt{\Delta}$$

70 Assuming that σ_f reflects both negative and positive outcomes from a risk perspective, we focus on only the negative outcomes (i.e., outcomes that lead to a negative settlement versus the RT price) when measuring the risk premium. To do so, we assume the distribution of outcomes is symmetric, and simply divide σ_f by 2 under the assumption that one-half the variability (that associated with positive settlement) requires no risk premium.

Based on a linear regression where a separate linear equation is estimated for each LMP quartile for on- and off-peak hours. Estimates of $\beta_{0,i,p}$ and $\beta_{i,p}$ are estimated using historical data on market outcomes in New England's electricity markets.

With this risk premium adjustment, the bid will be the expected closeout cost adjusted for the risk premium – that is:

$$offer_{i,t} = CVC + PVC = E[max(0, RT\ LMP - K)] * (1 + r_{o,i,t}) = E[\cdot] * \left(1 + r_{f,t} * \frac{R_t}{C_t} * \frac{\sigma_o}{\sigma_f} * p_i\right)$$
$$= E[\cdot] * (1 + k_t \sigma_{o,i,t} * p_i) = E[\cdot] * \left(1 + (k_t\beta_0 + k_t\beta_1\sqrt{\Delta^*_{i,t}}) * p_i\right)$$

Where

- $k_t = r_{f,t} * \frac{R_t}{C_t \sigma_f}$
- $E[\cdot] = E[max(0, RT\ LMP - K)]$ is calculated through fitted regression and Monte Carlo analysis, as described above
- $\Delta^*_{i,t} = m_i MC_i - K$, where m_i is an additional adjustment parameter to account for unit-specific cost factors such as start-up costs and fuel cost risk

Table 57. Operational and Intertemporal Factors Accounted for in Risk Premium

	Operational / Intertemporal Factors (p)			***Cost Factors (m)***		
	Performance Risk	Lead Time	Total	Fuel Cost Risk	Start-up Cost	Total
	[A]	[B]	[A]*[B]*[C]	D	E	[D]*[E]
Combustion Turbines						
Gas-only	1.05	1	1.05	1.5	1.45	2.18
Oil-only	1.05	1	1.05	1	1.45	1.45
Dual Fuel	1.05	1	1.05	1	1.45	1.45
Combined Cycle						
Gas-only	1.1	1.25	1.38	1.5	1.25	1.88
Oil-only	1.1	1.25	1.38	1	1.25	1.25
Dual Fuel	1.1	1.25	1.38	1	1.25	1.25
LNG Contract	1.1	1.25	1.38	1	1.25	1.25
Steam						
Oil-only	1.3	2	2.60	1	1.25	1.25
Dual Fuel	1.3	2	2.60	1	1.25	1.25

D. Posted Output Data

Along with this report, hourly results from the integrated production cost model for the Winter Central Cases and the Non-Winter Cases have also been publically posted. These data include market-clearing prices and quantities for DA and RT products (e.g. DA and RT energy, RT operating reserves, as well as DA AS products when applicable) in every hour of the modeled period. In addition, information on the day-ahead forecasted load is included for all cases, while various metrics related to the settlement of DA financial option products -- such as the hourly real-time closeout price, and the hourly FER/EIR price -- are included for ESI cases only.

For a given hour, these data present outcomes in the real-time market alongside that hour's corresponding day-ahead market outcomes. For example, hourly results listed for 12 PM on January 2nd, 2025 correspond to the real-time market solved in that hour and the day-ahead market solved on the prior day, for delivery the next day (i.e., the day-ahead market solved for delivery at 12 PM on January 2nd).

The quantities for DA and RT products reflect the total MW commitment across all resources in the New England region in a given hour. The clearing prices listed in these hourly results are the shadow price for the relevant product constraint, optimized over the entire New England fleet. For more information on how clearing prices for DA and RT products are set by the production cost model, please consult Section III.3 of this report.

For ESI cases, shortages for GCR, and RER energy option products occur when the total hourly commitment does not satisfy the hourly requirements (2,400 MW and 1,200 MW, respectively). EIR shortages occur when the sum of EIR and DA generation together in a given hour is less than the forecasted load quantity.