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Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives

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I. EXECUTIVE SUMMARY

Through its Strategic Planning Initiative (SPI), the New England Independent System Operator (ISO-NE) has identified multiple reliability concerns tied in part to the performance of generating resources in the region, including those with Capacity Supply Obligations (CSOs) made through ISO-NE's Forward Capacity Market (FCM). Concerns over performance include the potential failure of units to procure fuel, including natural gas-dependent resources during periods of limited gas supplies (particularly during the winter gas season),[1] and the failure of resources to closely follow dispatch requests when needed to address contingencies.[2] While these performance concerns exist today, the SPI recognized that they could become more important in the future, as aging units retire and the region integrates increased levels of renewable resources.

ISO-NE has taken a number of steps to address performance and reliability concerns in the near term, including, for example, an energy procurement (from non-gas resources) for Winter 2013/2014, and multiple changes to energy markets to mitigate coordination problems between gas and electric markets.[3] In addition, as a long-term solution to performance and reliability concerns, ISO-NE has proposed to modify the current FCM to include a Performance Incentives (PI) mechanism that would increase the current incentives for operational performance by providing additional revenues to resources that supply power (or reduce demand) during periods of the greatest system need. Under the FCM PI mechanism, these incentives are created through payments *between resources*, rather than between resources and load (customers) based on performance during reserve shortages. With each reserve shortage, higher performing resources would receive positive incremental payments, while resources that perform poorly would receive negative incremental payments. Thus, the aggregate payments by load (customers) will not exceed the fixed FCA prices regardless of the level of reserve shortages in the commitment period.

This report provides an Impact Assessment of the proposed FCM PI market rule changes, and its analyses are performed consistently with ISO-NE's framework for evaluating "major" initiatives, under which ISO-NE "will provide quantitative and qualitative *information* on the need for and the impacts, including costs, of the initiative"[4] (emphasis added). Thus, the Impact Assessment is designed to provide stakeholders with information about the possible impacts of the FCM PI proposal, including the potential benefits (including reliability improvements), costs, impacts on consumer payments, and other changes relevant to policy goals. However, it is not designed to provide a systematic evaluation of costs and benefits of the proposed rule, nor is it a forecast of FCM market outcomes.

[1] For example, *see* ISO-NE, "Winter Operations Summary: January-February 2013", February 27, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

[2] Analysis Group, *Analysis of Reserve Resources: Activation Response Following Contingency Events*, May 29, 2012. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/analysis_group_reserve_resource_analyses_5_29_2012.pdf.

[3] *See*, ISO-NE, "Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency," 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/interdependency_of_iso_proposals_to_key_spi_risks.pdf.

[4] ISO-NE and the Brattle Group, "Framework for Evaluating Major Initiatives," January 2011. Available at: http://www.iso-ne.com/pubs/spcl_rpts/2011/major_iso_initiatives_impact_analysis_final_report_1_28_11.pdf.

Market and system resource outcomes are evaluated through a quantitative model of bidding in the Forward Capacity Auction (FCA) for the 2018/2019 Commitment Period (FCA 9). The model allows comparison of outcomes with and without FCM PI, and comparisons between alternative proposals to address reliability concerns. Outcomes are evaluated under different assumptions about overall system conditions, including scenarios reflecting current ("Historical") conditions and postulated future conditions ("Equilibrium" scenarios). In addition, scenarios reflecting different levels of system reliability associated with limited gas fuel supplies are evaluated.

Table E1 summarizes these scenario results. Conclusions regarding impacts for reliability, costs and customers payments are as follows.

Table E1: Market and System Outcomes under Historical and Equilibrium Scenarios

		FCM PI, Historical Scenario			FCM PI, Near-Term Equilibrium Scenario		
	Current Rules (No FCM PI)	No Gas Shortages	Gas Shortages	High Gas Shortages	No Gas Shortages	Gas Shortages	High Gas Shortages
FCA Clearing Price ($/kW-month)	$1.31	$1.93	$2.55	$2.91	$3.76	$3.76	$4.49
Total FCM Payments ($bil)	$0.54	$0.80	$1.06	$1.20	$1.56	$1.56	$1.86
Avg FCM Payments ($/MWh)	$4.07	$5.99	$7.92	$9.01	$11.68	$11.66	$13.92
% Change Relative to 2012 Level	-57%	-36%	-15%	-4%	25%	25%	49%
New Entry Offers ($/kW-month)	$8.87	$8.67	$8.08	$7.49	$8.62	$8.09	$7.50
Surplus Capacity Above ICR (MW)	0	0	0	0	1,036	1,390	1,472
Expected Reserve Shortage Hours	21	-	-	-	9.00	10.00	12.75
Summer Peak RS Hours	21	-	-	-	9.00	7.00	6.75
Winter Gas-Related RS Hours	-	-	-	-	0.00	3.00	6.00
Incremental Dual Fuel Capacity (MW)	0	226	5,848	7,368	39	6,130	7,988

Note: For the Historical Scenario, Expected Reserve Shortage Hours are not reported as they do not reflect a consistent market-system equilibrium.

These results of this quantitative analysis indicate that FCM PI would likely result in improvements to reliability through several mechanisms.

First, the quantity of resources continuing to participate in the ISO-NE markets would increase under FCM PI compared to current market rules as a result of the additional revenues provided by performance incentives. In the near-term, estimated surplus capacity (above the Installed Capacity Requirement (ICR)) ranges from 1,036 MW to 1,472 MW with FCM PI in place. By comparison, the analysis finds there is no surplus economic capacity under current market rules.

Second, the analysis indicates that FCM PI would induce actions aimed at mitigating performance risks associated with gas supply curtailments, particularly during the winter gas season. The analysis finds that increased dual fuel capability provides the most cost-effective option to mitigate these risks. To the extent that other options (e.g., contracts with existing LNG resources, new pipeline capacity dedicated for electricity generation) become less costly to market participants than dual-fuel upgrades, our analysis would understate investment in reliability solutions. Across the range of winter gas market conditions evaluated, up to 7,988 MW of additional dual fuel capability is developed. Our sensitivity analysis found that the actual level of new dual fuel capability induced is sensitive to upgrade costs (and other assumptions regarding revenue streams), which suggests uncertainty in the eventual equilibrium between actions to mitigate gas curtailment risks and the level of such risks. FCM PI would also mitigate any further mothballing of dual-fuel capability that would likely occur absent market incentives, although the analysis does not quantify this risk to reliability (absent FCM PI).

Third, FCM PI would likely shift the resources that remain economically viable in the ISO-NE markets toward a more flexible mix. This likely change in performance can be seen in several analysis results. First, across scenarios, FCM PI decreases the quantity of "economic" (i.e., resources that can operate profitably in the ISO-NE markets) oil-fired resources, while increasing the quantity of economic demand response, imports, gas-fired and coal-fired resources. Second, because of FCM PI incentives, higher performing resources are more likely to continue to participate in the ISO-NE markets. Consequently, average resource performance (as measured by output during reserve shortages) of economic resources increases. The option to adopt dual fuel capability allows gas-fired resources with gas dependency risks to continue to operate profitably in the ISO-NE markets.

Analysis of the economic impacts of FCM PI considers both the costs of meeting customer loads, and the payments made by loads for wholesale market services.

FCM PI would result in a variety of cost impacts, with ambiguous near-term and long-term aggregate impacts. Impacts would include: potential changes to production costs due to a fleet of more efficient resources; new investments and higher annual costs to improve resource performance (including dual fuel capability investments of up to $462 million in the "high gas" scenarios); and potential delays in the timing of when new generation resources are required to meet the ICR.

The analysis indicates that FCM PI would likely raise FCA prices under most market conditions until the system requires additional generation resources, when FCM PI would likely lower FCA prices. The analysis finds that FCM prices in FCA 9 would be $1.31 per kW-month under current market rules, but would range from $1.93 per kW-month to $4.49 per kW-month across the various scenarios evaluated with FCM PI in place. However, FCM PI would likely lower offers from new entry due to the incremental revenues provided under FCM, particularly as these resources are likely to (and under FCM PI have incentives to) be high performing resources. Consequently, in the long-run, FCM PI could lower FCA prices as the market nears an equilibrium in which new generation resources are required. Increases in FCM payments under the Equilibrium scenarios (relative to 2012 levels) would reflect a 5% to 10% increase in 2012 wholesale energy payments.

The analysis indicates that total FCM payments would increase under FCM PI, although the net impact of increases in FCM expenditures, estimated at $0.26 billion to $1.32 billion across scenarios, would likely be lower due to reductions in energy market payments because of surplus capacity. Changes in energy market payments arising from surplus capacity are not quantitatively evaluated. Surplus capacity will also diminish the level of reserve shortages, which in turn reduces Reserve Constraint Penalty Factor (RCPF) payments. Based on current RCPF prices and the difference in the number of reserve shortages, the reduction in RCPF payments could range from about $63 to $265 million.

II. INTRODUCTION AND STUDY PURPOSE

Through its Strategic Planning Initiative (SPI), the New England Independent System Operator (ISO-NE) has identified multiple reliability concerns that appear to be tied in part to the performance of generating resources in the region, including those with Capacity Supply Obligations (CSOs) made through ISO-NE's Forward Capacity Market (FCM). Concerns over performance include the potential failure of units to procure fuel, particularly natural gas-dependent resources during periods of tight gas supplies (particularly during winter gas season),[5] and the failure of resources to closely follow dispatch requests when needed to address contingencies.[6] While these performance concerns exist today, the SPI recognized that they could become more important in the future, as aging units retire and the region integrates increased levels of renewable resources. The SPI also identified other reliability concerns, such as the need for more flexible resources to ensure reliable integration of variable resources. While perhaps not as urgent for New England at present, these reliability concerns could emerge in the longer term, as evidenced by developments in other regions, notably California.[7]

ISO-NE has taken a number of steps to address performance and reliability concerns in the near term, including, for example, an energy procurement (from non-gas resources) for Winter 2013/2014, and multiple changes to energy markets to mitigate coordination problems between gas and electric markets (e.g., the timing of day ahead energy market offers and clearing, the timing of supplemental commitments, and energy market reoffers during the real-time market). In addition, as a long-term solution to performance and reliability concerns, ISO-NE has proposed to modify the current FCM to include a Performance Incentives (PI) mechanism that would increase the current incentives for operational performance by increasing revenues to resources that supply power (or reduce demand) during periods of the greatest system need. This proposal is described in further detail in Section III of this report.

This report provides an Impact Assessment of the proposed FCM Performance Incentives market rule changes. The assessment has been developed in a manner consistent with the "Framework for Evaluating Major Initiatives" developed by ISO-NE, which provides guidelines for developing quantitative and qualitative *information* for evaluating "major" market design and planning initiatives.[8] While designed to provide stakeholders with information about possible *impacts* of the proposed rule changes (relative to current rules), including the potential benefit, costs, impact on consumer payments, and other changes relevant to policy goals, the Impact Assessment is not designed to provide a systematic evaluation of costs and benefits of the proposed rule, nor is it a forecast of FCM market outcomes. Impact analyses are developed for major market rule initiatives to improve the quality of stakeholder

[5] For example, *see* ISO-NE, "Winter Operations Summary: January-February 2013", February 27, 2013. Available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

[6] Analysis Group, *Analysis of Reserve Resources: Activation Response Following Contingency Events*, May 29, 2012. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/analysis_group_reserve_resource_analyses_5_29_2012.pdf.

[7] See, e.g., *Long Term Resource Adequacy Summit*, presentation by Mark Rothleder, California ISO, February 26, 2013. Available at: http://www.caiso.com/Documents/Presentation-Mark_Rothleder_CaliforniaISO.pdf.

[8] ISO-NE and the Brattle Group, "Framework for Evaluating Major Initiatives," January 2011. Available at: http://www.iso-ne.com/pubs/spcl_rpts/2011/major_iso_initiatives_impact_analysis_final_report_1_28_11.pdf.

deliberations, thus leading to better and more informed decisions based on the underlying merits of the proposals. Our Impact Assessment accomplishes this by providing both quantitative and qualitative assessment of the likely impacts of the FCM PI proposal, including changes to resource supply, mix and capabilities that have implications for system reliability; changes to production costs; and changes to market outcomes arising from FCM and energy market price effects.

The next section provides background on the FCM PI design. Following this, Section IV describes the analytic method for our Impact Assessment, and Section V outlines the data and assumptions applied in the analysis. Sections VI and VII present the result of our analysis, including the evaluation of both the FCM PI design and an alternative design proposed by NRG. Finally, Section VIII presents conclusions based on the analysis.

III. BACKGROUND ON FCM PERFORMANCE INCENTIVES PROPOSAL

ISO-NE is proposing FCM PI as a means to address concerns about the performance of resources that have taken capacity supply obligations under the FCM. Based on its assessment of resource performance under a variety of conditions, ISO-NE has concluded that the current approach to ensuring resource adequacy may not provide sufficient incentives for resources to perform when needed the most – that is, during reserve shortages. FCM PI is therefore designed to provide incentives for resource performance by rewarding resources that contribute to maintaining reliability by supplying output during periods of greatest system need. ISO-NE describes the approach as follows:

> The ISO proposes to modify the FCM design to make each resource's FCM revenue contingent, in part, upon its actual performance during periods when aggregate performance does not enable the ISO to satisfy system reserve requirements. The new performance incentive design will result in transfers from under-performing to over-performing resources, providing strong incentives for each resource to perform as needed and for resources that can meet the system's needs by exceeding their obligation to benefit by doing so. These incentives will place performance risk on all FCM resources, and this risk will need to be priced in each resource's bid in future capacity auctions.[9]

The FCM PI proposal operates under the simple principle that increasing payments for supply during periods of high reliability risk (as reflected by reserve shortages) provides the clearest incentive for resources to operate reliably during these periods. By using a market-based approach tied to an indicator that captures a wide range of reliability risks, FCM PI is designed to address any current or future risks to system reliability that may arise. Moreover, FCM PI addresses these risks through price signals that allow resources to mitigate these risks through the most cost-effective (i.e., least costly) actions. More information on the purpose and design of FCM PI may be found in Committee meeting materials and in ISO-NE's FCM Performance Incentives paper.

The FCM PI proposal includes several elements relevant to our Impact Analysis. First, under FCM PI, capacity supply obligations will still be established through the Forward Capacity Auction

[9] ISO-NE, "FCM Performance Incentives," October 2012. Available at http://www.iso-ne.com/committees /comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf.

(FCA) performed three years prior to the commitment period, and resources clearing in the FCA will still receive a price (P_{FCM}) for each unit of capacity that clears the FCA. Thus, the fixed revenue stream resources receive under current FCM rules will remain in place with FCM PI.

Second, FCM PI provides performance incentive payments to *all* resources that supply output during reserve shortages. These additional payments are set based on the quantity of output supplied (*MW*) and the Performance Payment Rate (*PPR*), set in terms of dollars per MWh (e.g., $5,455 per MWh). Thus, resources that supply output when the system is in greatest need are rewarded for their performance.

Third, for all resources with a CSO, FCM PI adjusts incentive payments to reflect the system average performance needed at the time of the reserve shortage. The benchmark for this average performance is the "balancing ratio" (*BR*), which is measured as the ratio of the system load when the reserve shortage occurs divided by the Installed Capacity Requirement (*ICR*). Thus, incentive payments are adjusted to reflect the size of each resource's capacity commitment (i.e., its CSO), the balancing ratio, and the *PPR*. In effect, FCM PI acts like a financial option. In exchange for taking on the CSO and receiving fixed FCM base payments, resources agree to pay an amount equal to *PPR*BR* (for each MW of a CSO) every time there is a reserve shortage. Across all resources in the region, this option hedges both resources and load from the financial risk associated with uncertainty about the future level of reserve shortages. Thus, the payments by load (and the FCM revenues to suppliers) remain fixed at the price set during the FCA regardless of the level of actual reserve shortages during the commitment period.

The revenue stream to an individual resource under FCM PI is:

$$R = P_{FCM} * CSO + \sum PPR * \left(MW - CSO * BR\right)$$

where the change to revenue streams from PI and the downward balancing ratio adjustments occur over all reserve shortages during the commitment period.

With the balancing ratio adjustments, the net effect of FCM PI for a particular resource depends on how well it performs compared to system needs, as reflected in the balancing ratio. Resources with "above average" actual performance (i.e., $MW > CSO * BR$) are rewarded for their performance by receiving positive revenue adjustments, while those with "below average" actual performance (i.e., $MW < CSO * BR$) are penalized for their performance through negative revenue adjustments. These adjustments to FCM revenues for resource performance will result in changes to FCA offers depending on a resource owner's expectations about the performance of their resource and other factors that could affect PI payments (e.g., the level of reserve shortages). The implications of FCM PI for resource offers are described further in Section IV.A, below.

FCM PI also introduces new uncertainties for resources. Whereas current FCM revenues depend only on the fixed FCM price *P*, FCM PI revenues will ultimately depend on factors not known to resources when their FCA offers are submitted. Thus, FCM PI introduces uncertainty over FCM revenue streams that will have implications for financial risk, which is addressed in Section V.F, below.

IV. FRAMEWORK FOR ASSESSING THE IMPACT OF PERFORMANCE INCENTIVES

The impact of FCM PI is assessed through a comparison of FCM market outcomes with and without FCM PI. Market outcomes reflect an equilibrium between the offers to take on CSOs made by market participants, and the quantity of CSOs required (equal to the ICR). ICR is determined by ISO-NE prior to the relevant FCA. In our analysis, we assumed the ICR was set at 34,500 MW, based on an ICR forecast for the 2018/19 capacity year developed in the Regional System Plan (RSP).[10] Given uncertainty over this quantity, we also consider values three percent higher and lower than this forecast.

A. Resource Offers With and Without FCM PI

Under the current FCM, offers to take on a CSO by existing and new resources reflect estimates of the incremental revenues required for the resource to "break-even" financially. This "break-even" amount reflects a resource's Going Forward Cost (*GFC*), which under current market rules must equal its expected avoidable costs from delisting (retiring) the resource (*FC*) (including the annualized cost of avoided investment, I) less its expected net revenues in ISO-NE energy and ancillary services markets. More specifically, under current rules, resource offers (in dollars per kW-month) equal:[11]

$$Offer(FCM)=\frac{GFC+RF}{Capacity*12}=\frac{FC+I-Q*\left(P-VC-HR*P_{Fuel}\right)+RF}{Capacity*12}$$

The GFC reflects net energy and ancillary services market revenues, where Q is the quantity of output sold, P is the average energy market price, VC is the non-fuel variable costs, HR is the unit's heat rate, and P_{Fuel} is the fuel price. The last term, RF, is the risk factor. A risk factor is added to offers to account for financial risks taken on by market participants when they agree to CSO contractual terms. Current market rules allow market participants to account for a defined set of risks related to unanticipated plant outages and potentially other factors. Given that *GFC* reflects costs during a future capacity commitment period, all values reflect forecasted or expected values. Appendix A provides details on how each of these values is estimated.

FCM PI introduces several changes to resource offers. First, for resources that require FCM base payments (i.e., based on the fixed price, P_{FCM}) to remain in the ISO-NE energy market, resource offers will reflect the unit's *GFC* plus expected revenues from FCM PI – that is:[12]

$$Offer(FCM\ PI)=GFC-PPR*H*\left(A-BR\right)+RF$$

[10] ISO New England, *2012 Regional System Plan*, November 2, 2012, page 45. Available at http://www.iso-ne.com /trans/rsp/2012/rsp_final_110212.docx.

[11] This formula reflects current market rules for net risk-adjusted going forward costs, as described in Market Rule 1, Section III.13.1.2.3.2.1.2. Throughout, the calculation of going forward costs is developed in a manner consistent with these market rules.

[12] Resources will require FCM revenues to remain in the market if going forward costs, net of PI revenues and the risk factor, are positive – that is: $GFC-PPR*H*A+RF>0$. Our analysis does not account for certain factors that could affect actual offers, including capital investment needed to continue production and option value given potential future positive changes in revenue streams.

where H is the *expected* level of reserve shortages (measured in hours), A is the unit's *expected average* performance over the course of the year, and BR is the *expected average* balancing ratio over the course of the commitment period.[13] Average performance A is measured as a unit's average output during reserve shortages (in MW) divided by its CSO. For example, a resource with a 100 MW CSO that produced average output of 65 MW during reserve shortages would have average performance A equal to 65%. Consequently, compared to the current market rules, FCM PI will result in upward and downward adjustments to offers depending on how each resource's *expected* average performance compares to the *expected* balancing ratio during reserve shortages.

Second, when submitting offers, resources can consider the option to forego a CSO. Without a CSO, market participants continue to receive positive PI payments for output from their resources. With a CSO, resources earn both the fixed FCM price and the positive incentive payment, but must consider the downward adjustments to revenues based on the balancing ratio (i.e., $PPR * CSO * BR$). Given this choice, in order to take on the CSO, market participants must receive a minimum payment that offsets the *expected* downward balancing ratio adjustments, which they could otherwise avoid by foregoing the CSO. Consequently, with PI, resources' offers will equal or exceed a minimum offer equal to their expectation of these downward adjustments – that is:

$$Minimum\,Offer\left(FCM\ PI\right) = PPR * H * BR + RF$$

This minimum offer differs from current market rules, under which some resources will be willing to accept a minimum offer as low as \$0 per kW-month.

Third, resources taking on a CSO may face less or greater financial risk due to the financial hedge provided by the CSO compared to uncertain (but positive) net PI payments. Consequently, the risk factor *RF*, reflecting financial risk due to the uncertain revenue streams from accepting a CSO, included in resource offers may differ under FCM PI compared to current market rules. Note that, in theory, this adjustment could be upwards or downwards depending on the resource's expected performance and the aggregate risk profile of the entity that owns the asset.

To determine the clearing prices in the FCA, offer curves are constructed, reflecting the bids from each resource ordered from lowest to highest priced offers. Offer curves are developed for the 2018/2019 FCA with and without FCM PI. Offers are developed assuming resources offer their entire capacity as a single block, rather than as multiple blocks as allowed under the proposed rules. Section V describes how each of the individual terms in the offer formulas described above is calculated.

B. Scenarios Evaluated

A significant uncertainty affecting the analysis relates to the likely resource and system conditions in the 2018/2019 Commitment Period. These conditions affect key factors that must be

[13] For further discussion of the calculation of expected FCM payments *see* Gillespie, Andrew et al., ISO-NE, "FCM Performance Incentives," NEPOOL Markets Committee, April 9-10, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps /mrkts_comm/mrkts/mtrls/2013/apr9102013/a17a_iso_presentation_04_10_13.ppt.

considered in developing resource offers, including the likely level of reserve shortages hours, and the likely resource performance and balancing ratio during those shortages.

Current market conditions may not be a reliable predictor of future market conditions for several reasons. First, the price floor that supports the FCM price has resulted in a supply of resources in the ISO-NE region well in excess of the ICR. Starting in FCA 8 (for the 2017/2018 Commitment Period), the price floor will be removed, which could lead some resources to temporarily or permanently exit the market; this, in turn, would affect system conditions. Second, ISO-NE has identified that gas fuel supply limitations (particularly during winter months) pose a meaningful risk to system reliability.[14] While ISO-NE has taken many steps to improve the market's ability to mitigate these risks (e.g., intra-day reoffers, hourly offers, adjustment to the timing of the day ahead market, increases in the Reserve Constraint Penalty Factor (RCPF) for 30-minute system reserves, procurement of requirements for 30-minute "replacement" reserves)[15], this reliability risk could increase with time, particularly if resources retire due to lower FCM revenues or other economic factors.[16]

Given these uncertainties, the impacts of the FCM PI proposal are evaluated under multiple sets of assumptions regarding system conditions in order to identify the range of potential outcomes and the robustness of conclusions. Table 1 lists the scenarios and sensitivity cases we evaluated. At one end of the spectrum are "Historical" scenarios reflecting system conditions that have prevailed in recent years. However, given the potential for a net reduction in the region's resources (particularly with the removal of FCA price floors), we also develop a near-term Equilibrium scenario which reflects a postulated balance between forecast system conditions and expected market conditions in 2018/2019. For reasons we describe below, this scenario is a reasonable upper bound on prices. This near-term equilibrium may differ from a long-run equilibrium, where the system requires the entry of new generation resources to maintain resource adequacy. While we do not explicitly postulate long-run equilibrium conditions for 2018/2019, some of our results are informative to understanding outcomes under such conditions.

Along with uncertainty about system conditions, there is also uncertainty about the expected level of reserve shortages that arise specifically from limitations to gas supplies. While ISO-NE has taken steps to mitigate reliability risks related to coordination of gas and electric markets, these market enhancements are not expected to eliminate all reliability problems, particularly those arising when there are insufficient resources with fuel supply to meet load. To assess possible system conditions associated with winter gas reliability risks, additional scenarios are evaluated assuming there are 3 or 6 hours of reserve shortages associated with limited gas supply during winter months. Table 1 identifies the six scenarios we analyze, reflecting the different potential system conditions described above.

[14] For example, *see* ISO-NE, "Winter Operations Summary: January-February 2013", February 27, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

[15] *See*, ISO-NE, "Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency," 2013. http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/interdependency_of_iso_proposals_to_key_spi_risks.pdf.

[16] For example, Entergy has announced the retirement of the Vermont Yankee nuclear plan. Available at http://www.safecleanreliable.com/entergy-to-close-decommission-vermont-yankee-2.

In addition to these scenarios, we also consider the sensitivity of results to multiple underlying assumptions related to resource availability and costs, including elimination of offer risk factors; costs for compliance with environmental regulations (Clean Water Act (CWA) Section §316(b) cooling water intake requirements); the cost of dual fuel upgrades; and limitations on the ability of gas-dependent resources to develop dual fuel capability. These sensitivities and the underlying model assumptions are also included in Table 1.

Table 1: Alternative Scenarios and Sensitivities Considered

		Winter Gas Dependency Risks		
		No Gas Shortages	**Gas Shortages**	**High Gas Shortages**
Overall Resource Adequacy	**Current ("Historical") System Conditions**	Historical: No Gas	Historical: Gas	Historical: High Gas
	Near-term Equilibrium System Conditions for 2018/2019	Equilibrium: No Gas	Equilibrium: Gas	Equilibrium: High Gas

Sensitivity	Model Assumptions
Risk Factor	• Use Equilibrium: No Gas Scenario • No Risk Factor
Environmental Costs	• Use Equilibrium: No Gas Scenario • Incremental costs for compliance with CWA Section §316(b) Cooling Water Intake Requirements (Section V.E provides details on costs)
Dual Fuel Costs	• Use Equilibrium: Gas Scenario, and Equilibrium: High Gas Scenario • Increase dual fuel upgrade costs by 25% • Results reported/discussed in Section VI.A.2 (all other sensitivities reported/discussed in Section VI.D)
Dual Fuel Restrictions	• Use Equilibrium: High Gas Scenario • Limits dual fuel adoption to those already with decommissioned dual fuel capability

V. DATA AND ASSUMPTIONS

A. Going Forward Costs

Section IV.A provides the basic framework for calculating each unit's going forward cost (GFC). Each unit's GFC for the 2018/2019 Commitment Period is based on a combination of data on current operation costs, past utilization rates, and forecasts of future fuel prices. Future electricity prices are estimated based on the past relationships between natural gas prices and the average prices earned by resources when operating. Estimates rely on a variety of data sources, including: SNL for unit-level fixed costs, non-fuel variable costs, and heat rates; EIA and NYMEX for fuel price forecasts; and ISO-NE for historical output and prices. Appendix A provides details on the data and approaches used.

B. Estimating Unit Performance and Balancing Ratio During Reserve Shortages

Unit performance and the balancing ratio are estimated to reflect the system conditions during reserve shortages under the scenarios evaluated for the 2018/2019 Commitment Period. Three system conditions are considered:

1. Historical Conditions, corresponding to average conditions in recent years, with the current level of surplus resources;
2. Peak (Summer) Conditions, corresponding to reserve shortages arising as a consequence of an inadequate level of resources to meet load; and
3. Winter Peak Conditions, corresponding to reserve shortages arising due to limitations on natural gas supplies during the peak winter gas season.

Average performance is measured for each unit based on output supplied during reserve shortages over the period 2010 to 2012. Estimates of likely performance during Historical, Peak (Summer) and Winter conditions are based on actual performance during reserve shortages that reflect these types of system conditions. Thus, for example, estimates of unit performance and the balancing ratio during reserve shortages due to resource adequacy risks (i.e., Peak Summer Conditions) are based on reserve shortages during the 2010 to 2012 period that also occurred due to insufficient aggregate resources.[17] Balancing ratios are estimated in a consistent fashion.

Figure 1 shows the average performance by resource type for each of the three market conditions described above, along with the balancing ratio during the corresponding time periods. Tables 1 to 3 in Appendix A provide additional statistics on average performance *A* across the same set of units. These additional tables show some skewing of performance within resource categories with larger resources tending to demonstrate higher performance.

[17] Other reserve shortages during the 2010 to 2012 time period occur due to other factors, including having insufficient resources committed to respond to unanticipated changes to load or supply.

Figure 1: Average Unit Performance by Resource Category

[1] Unit performance for each class is calculated as total class output divided by total class summer SCC. The summer SCC used is from the most recent year with available data.
[2] Summer SCC, generation type, and primary fuel type from CELT Reports. Operating data from ISO-NE.

Resource performance varies widely across resource categories. Nuclear power has the highest non-renewable performance because, as baseload resources, they operate under all market conditions. Gas turbines also have high performance because these resources are capable of starting quickly under circumstances when the market needs additional resources to meet load plus reserve requirements. Combined cycle and coal resources have somewhat lower performance because when reserve shortages occur these resources may not be committed or able to ramp up to their full operating capacity, if there is limited foreshadowing of the need for additional resources to meet load plus reserve requirements. Non-CT oil-fired resources have the lowest performance because many of these facilities are operated only when prices are sufficiently high to merit operation, or when there is sufficient foresight that the system will need additional resources to maintain reserve levels. Renewable resource performance varies with the particular characteristics of each type of resource. Wind resources have average performance that exceeds their eligible capacity, because FCM eligible capacity represents only of faction of the nameplate capacity of these resources. Hydro performance is high, potentially reflecting either high utilization or control of the timing of output. Pumped storage performance is below that of other hydro, suggesting either that reservoirs have been drained or have not been filled prior to reserve shortages.

Comparison of resource performance to the balancing ratio provides an indication of how each resource category fares under PI. Resources with performance above the balancing ratio would receive positive revenue adjustments, while those with performance below the balancing ratio would receive negative revenue adjustments. While the average performance levels reported in Figure 1 are indicative of the resource category performance, there is substantial variation in the performance within each category and the performance of individual units may differ from these category averages.

C. Reserve Shortage Hours

The level of reserve shortages is measured by the expected number of hours of reserve shortages over the 2018/2019 Commitment Period. The level of reserve shortages for each scenario evaluated is reported in Table 2. For the Historical Scenarios, the level of reserve shortages is based on market conditions from 2010 to 2012, when there was an average of 3.2 hours of reserve shortages annually.[18] Consequently, we assume 3.2 reserve shortage hours in the Historical Scenarios, to reflect current market conditions.

Near-term equilibrium conditions reflect a balance between system and market conditions for FCA 9, which procures commitments for the 2018/2019 Commitment Period. This near-term equilibrium will reflect resources that remain in the market due to FCM revenues, as well as resources that stay in the ISO-NE energy and ancillary services market without a CSO.

Under the current FCM market rules, resources that do not clear in the FCM do not have an obligation to remain in the market. However, assuming that delist offers reflect going forward costs (and

[18] This average reflects a combination of shortages due to insufficient resources (i.e., high loads relative to resources) and shortages due to unanticipated system conditions (particularly when there are insufficient resources committed).

that the FCA clearing price is greater than zero), failure to clear the market suggests there is a meaningful likelihood that a resource will exit the market.[19]

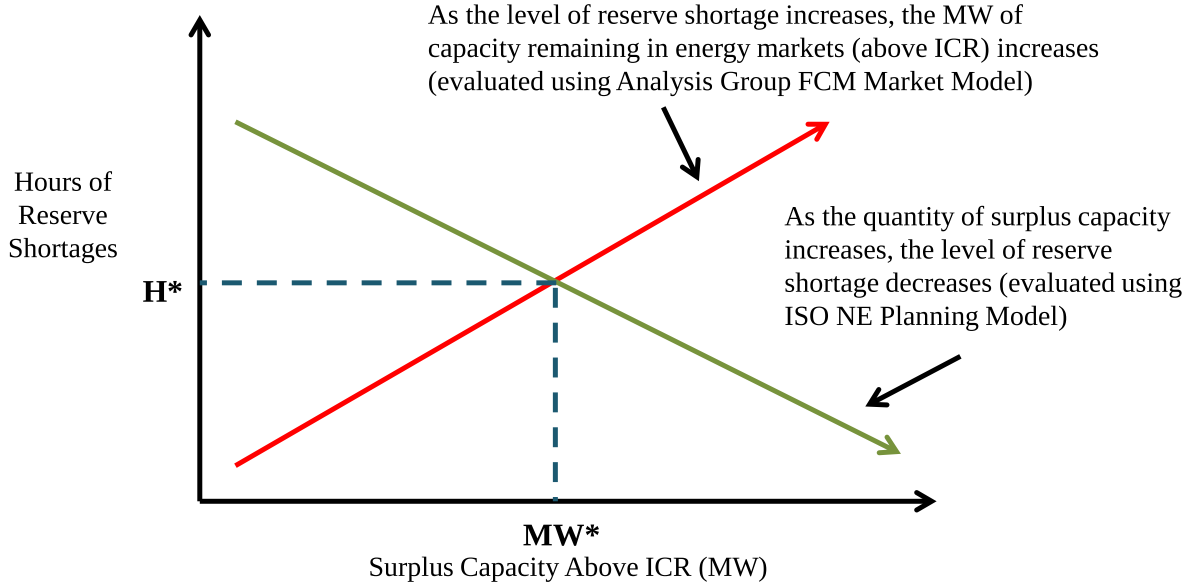
Table 2: Reserve Shortage Hours by Scenario

	Reserve Shortage Hours			
Scenario	**Historical**	**Peak (Summer)**	**Winter Gas**	**Total**
Historical: No Gas	3.2	0	0	3.2
Historical: Gas	3.2	0	3	6.2
Historical: High Gas	3.2	0	6	9.2
Equilibrium: No Gas	0	9	0	9
Equilibrium: Gas	0	7	3	10
Equilibrium: High Gas	0	6.75	6	12.75
No Risk Factor	0	9	0	9
Environmental Costs	0	9	0	9
Higher Dual Fuel Costs	0	7/6.75	3/6	10/12.75
Dual Fuel Restrictions	0	6.75	6	12.75

By contrast, under FCM PI, resources may find it financially profitable to remain in the ISO-NE energy market without a CSO. This can occur when the market clears at a price that is below the resource's minimum offer (based on its expectations of the level of future reserve shortages) but the resource does not need the FCM revenues to remain economically profitable (i.e., its going forward costs including PI revenues are less than zero). As the duration and frequency of reserve shortages increases, the additional PI revenue increases the number of "economic" resources that can profitably operate without a CSO. This is illustrated conceptually in Figure 2, which shows with the red line the relationship between the levels of surplus capacity for varying levels of reserve shortages. However, from a system perspective, as the quantity of resources increases, system reliability improves, which reduces the expected duration and frequency of reserve shortages. This is illustrated by the green line on Figure 2. The *equilibrium* level of reserve shortages and surplus capacity reflects equilibrium between these two opposing dynamics. Our analysis of the near-term Equilibrium for FCA 9 assumes the internally consistent level of surplus capacity and reserve shortages hours that arises under this equilibrium.

[19] In practice, resources may not exit due to a variety of factors, including the option of remaining and continuing to operate without an obligation in the hopes of higher future net revenues.

Figure 2: Graphical Depiction of Equilibrium Between Excess Resources and Reserve Shortages



The market model curve is estimated using the FCM PI model described in this report.[20] The system model is a probabilistic simulation model used by ISO-NE to establish ICR for the region given anticipated load and system conditions for the 2018/2019 Commitment Period.[21] The reserve shortages analyzed in this ISO-NE system model are driven by conditions in which there are insufficient resources available to meet load plus reserve requirements. Because reliability risks arising due to insufficient resource adequacy are most significant during summer peak load periods, the reserve shortages identified in the ISO-NE system model occur largely during the summer months.

Our analysis does not explicitly analyze the evolution of the FCM market toward a long-term equilibrium. This equilibrium can be characterized by the retirement of some existing resources and the entry of new resources as the FCM prices reach the cost of new entry. The timing of the retirement of existing resources will depend on many factors, including the degradation of performance (e.g., heat rate) over time, increasing maintenance costs and incremental capital expenditures to plant systems. Because of uncertainty over these factors, we have not attempted to analyze the evolution of market outcomes towards such an equilibrium. However, below we provide certain quantitative and qualitative information to inform understanding of how PI will affect the timing of and prices at the long-run equilibrium.

[20] Our analysis assumes that resources that either do not accept a CSO or that have insufficient expected revenues to operate profitably in the ISO-NE energy markets will (temporarily or permanently) exit these markets. To the extent that resources do not exit due to a positive option value to continue operations given potential profitable operation in future commitment periods or other factors, then our results would tend to understate the supply of excess resources relative to what would actually happen, which in turn would overstate the expected level of reserve shortages.

[21] ISO-NE Market Development, "Operating Reserve Deficiency Information – At Criteria And Extended Results," July 5, 2013. Available at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jul10112013/a12a_iso_memo_07_05_13.pdf.

Analysis of reserve shortages arising from limitations on gas supply during winter months is performed by evaluating market outcomes with two different levels of winter reserve shortages: 3 and 6 hours of winter gas shortages.[22] As with reserve shortages arising due to insufficient resources to meet load and reserve requirements, shortages arising due to over-reliance on limited gas supply will reflect a balance between the number of reserve shortages and the quantity of gas-dependent resources. On the one hand, as the level of reserve shortage hours increases, this creates incentives for resources to take steps to limit their dependence. On the other hand, as resources take steps to limit their gas dependence (in response to these incentives), the number of reserve shortage due to gas dependence would decline. Absent specific data on the likelihood of reserve shortage driven by gas dependence, however, we try to capture this potential impact by modeling up to six hours of gas-driven shortages (in addition to modeling no gas-driven shortages).[23]

Gas shortage scenarios are evaluated under both Historical and near-term Equilibrium conditions. In the near-term Equilibrium scenarios, a separate equilibrium is calculated for each scenario based on the FCM market response with different mixes of summer peak and winter gas reserve shortages. As shown in Table 2, the resulting level of reserve shortages reflects a mix of peak (summer) and winter gas reserve shortages. Equilibrium with winter gas reserve shortages are calculated assuming that equilibrium with the ISO-NE system model reflects only summer peak reserve shortages. This approach is consistent with the fact that a disproportionate number of reserve shortages identified in the ISO-NE system model occur during summer months.

D. Technical Options for Improving Performance

FCM PI is designed to create incentives for asset owners to take steps to improve the performance of existing resources, and/or choose higher performing technologies when investing in new resources. Resource owners can take many steps to improve resource performance, including operational practices to reduce forced outages and improve plant responsiveness to operator requests, investments to improve fast start capability and ramping rates, and actions to firm-up fuel supplies.

Under FCM PI, resources will find it economically beneficial to undertake actions to improve performance when the expected incremental revenues, including PI and other incremental revenues, exceed the costs of the actions taken, including annual expenditures and up-front capital investment. The expected level of incremental PI revenues will depend on multiple factors, including the expected level of reserve shortages and the improvement in the resources' expected performance (output) during these periods.

[22] Even as resources take action to address gas dependence, reserve shortages could remain. For example, the time for many dual fuel resources to switch to alternate fuels varies, such that some resources may require an hour or more to switch. During this period, the system will face resource limits that could result in reserve shortages.

[23] To date, while there have been many instances of reliability challenges tied to gas supply limitations during winter and non-winter months, there is not clear information on the relationship between market conditions related to gas supply and reserve shortages. Due to this fact and the many uncertainties about forecasting future market conditions, we have not attempted to quantitatively model the likelihood of reserve shortages arising from gas dependence.

Our analysis considers potential steps that resources with gas fuel curtailment risks – "gas-dependent resources" – may take to address limited natural gas availability, which would most likely or most often occur during the winter months. We do not consider other actions resources might take to generally improve their operational performance, given the lack of information about such opportunities for individual resources in the region.

The analysis of potential resource responses to FCM PI during winter gas shortages involves two steps. First, we compare the relative cost and effectiveness of alternative means of securing fuel supplies to identify the most cost-effective option. Second, we integrate this option into the FCM supply model such that resources develop dual fuel capability when there are sufficient incremental PI revenues to justify this investment.

Identification of the most cost-effective option for securing winter fuel supplies considered four alternatives:

1. Dual fuel capability
2. Firm or option service from existing Liquefied Natural Gas (LNG) facilities
3. LNG storage
4. Firm transportation services from a new gas pipeline

Table 3 summarizes the results of our assessment of the costs and effectiveness of these alternative options, with further details on our assessment provided in Appendix C. Our analysis of costs reflects the direct expenditures and investments required to implement the technical options for securing fuel supply, but does not consider all changes in revenues or costs that may occur with each option. For example, the costs of firm pipeline service from a new pipeline includes the incremental rates charged for such service, but does not account for the potential reduction in gas transportation costs during periods of tight gas supply (i.e., when the basis differential exceeds the tariff rate). In effect, our analysis considers the least-cost means to address the performance risks that are the focus of this report. While we identify and qualitatively describe differences in the effectiveness of these alternative services at securing fuel supply, this effectiveness does not enter into our identification of the most cost-effective option.

As shown in Table 3, the cost of alternative technologies varies widely. These estimates are based on multiple sources identified in Appendix C, including publicly available data and data provided by ISO-NE, but are not based on detailed engineering studies. Development of dual fuel capability appears to be the least cost option evaluated. Annualized costs range from $6,500 per MW for facilities with moth-balled or decommissioned dual fuel capability to $15,000 per MW for facilities that have never had dual fuel capability.[24] In principle, existing LNG facilities could provide service at a comparable cost to dual fuel capability. The rates for firm or option service provided by these facilities will depend on demand charges that facility owners have some discretion in setting. Costs for new LNG storage are roughly $30,000 per MW, significantly higher than incremental dual fuel costs. Costs for firm transportation service, reflecting the rates charged for such service, are also higher than dual fuel costs.

[24] Annualized costs reported in Table 3 reflect particular assumptions about discounting, depreciation terms and other factors that may differ from those used in the FCM PI analysis, but are comparable across the alternatives for addressing gas-dependency evaluated.

Table 3: Comparison of Options for Firming Gas-Dependent Resource Fuel Supply

<table>
<tr><th colspan="2">Technology Option</th><th>Cost</th><th>Other Factors</th></tr>
<tr><td rowspan="3">Dual Fuel</td><td>Current
Dual Fuel Capable</td><td>• $5,700 per MW</td><td rowspan="3">• Time to recommission or install is relatively brief
• Long refill times may limit effectiveness over long curtailments
• Operations limits and risks when switching to alternate fuels
• Requires environmental permitting</td></tr>
<tr><td>Under- or Unutilized Dual Fuel Capability</td><td>• $6,500 per MW (annualized, reflecting capital cost and annual expenditures)</td></tr>
<tr><td>No Dual Fuel Capability</td><td>• $15,000 per MW (annualized, reflecting capital cost and annual expenditures)</td></tr>
<tr><td colspan="2">Service from Existing LNG Facilities (Canaport, DOMAC)</td><td>• Not estimated – cost would reflect (1) foregone opportunity to sell LNG in higher-value markets; (2) carrying cost; (3) operating cost; and (4) transportation charge.
• Rate would be subject to negotiation</td><td>• Could be subject to deliverability constraints without firm service (esp. for Canaport, requiring transport over Maritimes pipeline)</td></tr>
<tr><td colspan="2">New LNG Storage</td><td>• $29,700 per MW (annualized, reflecting capital cost and annual expenditures)</td><td>• Long refill times may limit effectiveness over ong curtailments</td></tr>
<tr><td colspan="2">New Pipeline Capacity</td><td>• $9,700 to $32,700 per MW for upfront costs
• Rates for firm service would exceed these annualized costs</td><td>• Requires purchase of firm service
• Time lag between commitments for firm service and new service availability
• Reduces transport costs during periods of elevated prices (when basis differential exceeds tariff rate)</td></tr>
</table>

Our analysis allows gas-dependent resources to invest in dual fuel capability if the expected incremental FCM PI revenue streams are sufficient to cover the incremental costs, including any up-front investments and annual expenditures. Incremental FCM PI revenue streams reflect two factors. First, with dual fuel capability, a gas-dependent resource has a higher likelihood of supplying output during a gas supply related reserve shortage. The analysis assumes a 50% reduction in the average performance *A* of gas-dependent resources during winter gas shortages; this assumption is designed to strike a balance within the range of curtailment levels that resources may experience during gas reserve shortages. Investment in dual fuel capability eliminates this reduction, allowing the resource to operate at a normal performance level. For example, a gas-dependent resource with a performance *A* of 70% would operate at a 35% performance during winter gas reserve shortages unless it invests in dual fuel capability. While considering incremental FCM PI revenue streams, the analysis does not account for other changes in net revenues that might arise from dual fuel investment, including changes in energy market revenues. The second factor affecting the incremental revenues from a dual fuel investment is the level of winter gas reserve shortages. For example, if the resource in the example above expects 3 hours of winter gas reserve shortages, then it would expect to earn an incremental 1.05 MWh during reserve shortages, or \$5,728 at a *PPR* of \$5,455 per MWh from investing in dual fuel capability.[25]

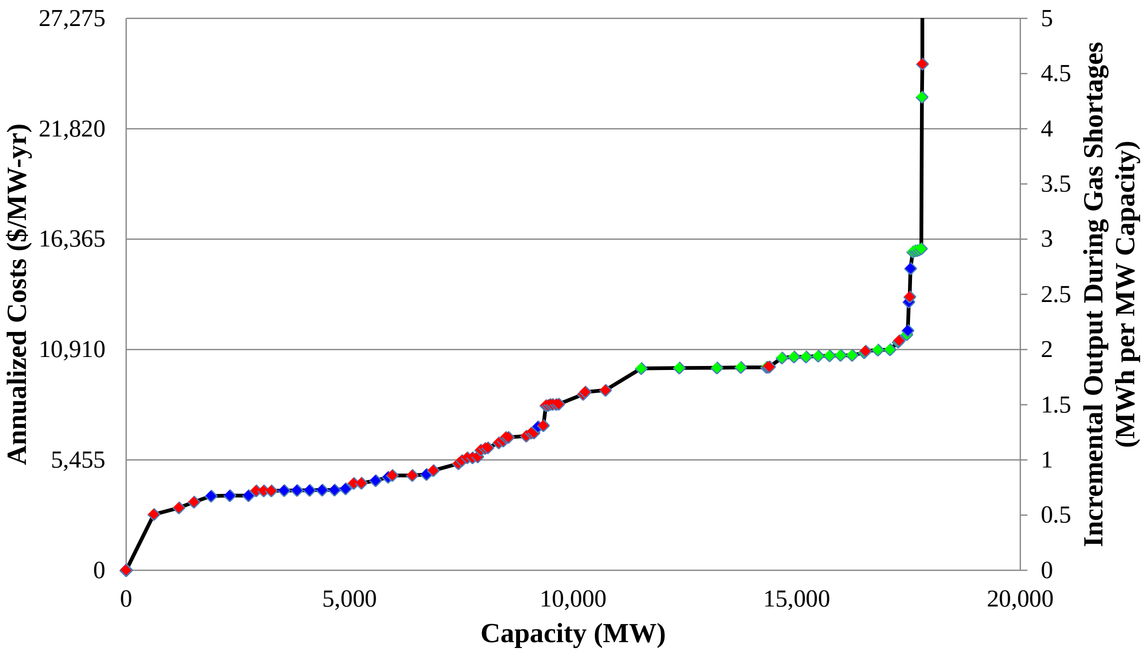
Figure 3 shows the dual fuel supply curve for existing gas-fired resources.[26] This curve includes resources currently without dual fuel capability, as well as resources currently with dual fuel capability that need to incur costs to cover on-going maintenance of dual fuel capability and fuel supplies. The decision to invest in dual fuel capability reflects lower costs for units with mothballed capability, and no limitations arising from environmental permits or other factors. Costs are reported in terms of annual expenditures per MW of capacity, as well as the number of incremental MWh of output during reserve shortages (at a *PPR* of \$5,455 per MWh) that is sufficient to cover these annual expenditures. The figure shows that FCM PI can create incentives for investment in dual fuel capability when the resource expects to there to be winter gas shortages in the commitment period. For example, at 2 incremental hour of output during a gas related reserve shortage, roughly 11,000 MW of additional dual fuel capability is supported, including over 7,000 MW of incremental dual fuel capability from resources currently without this capability. Appendix C provides more details on the estimation of costs associated with investment in dual fuel capability.

The analysis assumes that all existing dual fuel resources retain this capability with and without FCM PI. As shown in Figure 3, maintaining dual fuel capability imposes costs on asset owners from on-going maintenance and holding of fuel supplies. Absent market incentives, these resources could opt to mothball this capability, as many resources have already done in recent years. By assuming that resources preserve dual fuel capability absent FCM PI, the analysis may understate FCM PI reliability benefits by failing to capture these potential losses of dual fuel capability.

[25] That is, $PPR * H * (A_{with\ dual\ fuel} - A_{without\ dual\ fuel}) = \$5{,}455 / MWh * 3\ hrs * 35\% = \$5{,}728 / MW$.

[26] Note that differences between annualized costs in Table 3 and Figure 3 reflect differences in certain assumptions, including discount rates and depreciation periods assumed in each analysis.

Figure 3: Supply Curve for Dual Fuel Resources, including Development and Annual Expenditures



Note: Each symbol corresponds to an individual facility, with existing dual fuel resources in RED, facilities with decommissioned dual fuel capability in BLUE and facilities with no dual fuel capability in GREEN.

E. Potential Environmental Compliance Costs

Compliance with emerging U.S. Environmental Protection Agency (EPA) rules could require that certain facilities undertake additional investments and in future years face additional expenditures in order to obtain permits for continued operation. While EPA has promulgated multiple regulations affecting air emissions, water discharges and waste management from power generation facilities, the regulation most likely to impact facilities in ISO-NE market is Section §316(b) of the Clean Water Act, which requires power plant cooling water structures to meet certain technological requirements in order to minimize adverse environmental impact, largely to aquatic life.[27] Because compliance requirements with these regulations are uncertain, we assume no incremental compliance requirements as the baseline assumption, but consider a sensitivity analysis with additional compliance requirements. In the compliance sensitivity analysis, units must take incremental action to comply with Section §316(b), but some units are left unmodified because their water sources suggest that the units have already made modifications or are unlikely to require retrofits. The identification of resources subject to Section §316(b) requirements reflects both fuel/technology type, and resource age under the assumption that many newer steam units are already compliant with Section §316(b). This case assumes that 50% of the overall capacity

[27] For more information on §316(b), *see* Environmental Protection Agency, "Cooling Water Intake Structures – CWA §316(b)," http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm.

potentially at risk actually faces additional Section §316(b) requirements, including all coal units, the two oldest nuclear plants, and the oldest oil units.

Compliance requirements have two implications for facility performance. First, compliance imposes additional going forward costs, including upfront investment and annual operating expenditures.[28] Second, the facility's rated capacity is diminished and heat rate is increased.[29] These penalties stem from the efficiency decrease and power required to drive water pumps in the new cooling towers. The adjustment to GFC when compliance requirements are assumed reflects both these direct and indirect cost impacts. Further detail on our approach is provided in Appendix A.

F. Risk Premiums

Market participants may include a risk factor in resource offers under both current rules and proposed rules for FCM PI. Under current rules, the risk factor can reflect certain pre-determined elements. To simplify the analysis, we assume the risk factors incorporated in resource offers without FCM PI equals zero. The remainder of this section addresses risk factors under FCM PI.

FCM PI introduces additional uncertainty about FCM market revenues that can have consequences for the financial risk faced by market participants. Under the current FCM, resources face uncertainty about their future costs and energy market net revenues when developing their offers. However, the revenue stream from the current FCM model is fixed after the FCA clears, assuming resources comply with their capacity obligation. However, with the introduction of FCM PI, future FCM revenue streams depend on system conditions beyond the resource's control (e.g., the frequency and duration of reserve shortages, and the balancing ratio during these shortages) and factors over which it has only partial control (i.e., the resource's performance during future reserve shortages). As a result of these uncertainties, future FCM revenues streams for individual resources will be uncertain, which is not the case under the current FCM model. Moreover, for poorly-performing resources, these downward adjustments could be large enough to erode most of the fixed portion of revenues under FCM PI (based on the fixed FCA price), or even result in negative total FCM payments.

Assessing the financial risk posed by FCM involves many challenges. First, the entities that own resources in the ISO-NE markets vary widely. Some are relatively small, owning several or even only one asset. However, many are large and have a wide variety of physical and contractual assets, along

[28] The going forward cost is based on estimates from: North American Electric Reliability Corporation, "Potential Impacts of Future Environmental Regulations: Extracted from the 2011 Long-Term Reliability Assessment," November 2011. Available at http://www.nerc.com/files/epa%20section.pdf.
[29] Steam turbines are given a heat rate penalty of 1.3% and a capacity penalty of 3.4%. "Electricity Reliability Impacts of a Mandatory Cooling Tower Rule for Existing Steam Generation Units," U.S. Department of Energy Office of Electricity Delivery and Energy Reliability, October 2008, p. 22. Available at: http://www.netl.doe.gov /energy-analyses/pubs/Cooling_Tower_Report.pdf. Nuclear plants are given a heat rate penalty of 1.5% and a capacity penalty of 1% of based on a variety of sources. Wheeler, Brian, "Retrofit Options to Comply with 316(b)," Power Engineering, October 2010. Available at: http://www.power-eng.com/articles/print/volume-114/issue-10/features/retrofit-options-to-comply-with-316-b.html; "Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule," U.S. Environmental Protection Energy, pp. 175, 207-210. Available at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/phase2/upload/2009_03_26_316b_phase2 _devdoc_ph2toc.pdf. No adjustments to operating performance *A* have been made for these impacts.

with other business operations. Some entities own portfolios of generation (and contractual) assets with different performance characteristics, different markets and different geographical locations. The revenue streams received through these assets varies widely depending on the type of asset (gas/oil/nuclear, dispatchable/intermittent, old/new, fast-start/non-fast-start), the particular market (e.g., in New England there is the energy, operating reserves, ancillary services, and RECs along with the FCM) and geographies (including other RTOs and assets supported by long-term contracts). Moreover, some entities have revenue streams outside of wholesale power markets, including transmission, distribution, retail, market-making or even non-electric business entities.[30]

Second, the design of FCM PI partially mitigates financial risks for entities with multiple resources in the ISO-NE market, and creates opportunities for bilateral transactions to mitigate risks. For entities that own multiple ISO-NE resources, differences in the actual performance of those resources will tend to mitigate the risk of any individual resources due to portfolio effects. These portfolio effects are considered in the quantitative analysis of the risk factor. In addition, as discussed earlier, under FCM PI, total revenues to all resources in the region are fixed.[31] Consequently, as a whole, the region's resource fleet is fully hedged against the FCM PI financial risks faced by individual resources.[32] This fact suggests that there are opportunities for bilateral transactions among entities in the region that could mitigate the risks faced by individual entities.

Third, financial products could be developed to help mitigate financial risks. For example, an option could be developed that pays the owner based on the level of reserve shortages during a given period. If market participants with a CSO purchased such a product, then with every reserve shortage they would receive a payment from the option that could offset (to some degree) the downward revenue adjustment based on the balancing ratio.[33]

The likelihood that markets for these FCM PI options or bilateral transactions between market participants would emerge is highly uncertain at this stage. Thus, assessment of risk cannot presume that they will develop. However, to the extent that the analysis indicates that there are high risk premiums associated with FCM PI offers, this suggests that the financial rewards to developing these markets or transactions would be higher, which would increase the likelihood that these mitigating transactions would emerge. Should they emerge, these alternatives would result in additional financial costs, which would be reflected in resource offers through the risk factor. The quantitative analysis of the risk factor under FCM PI does not consider these costs, which would tend to increase resource offers and thereby raise FCA prices under FCM PI.

[30] A recent study indicated that Calpine and NRG were the only two publicly traded merchant generation companies. Brattle Group and Sargent & Lundy, "ISO-NE Offer Review Trigger Prices 2013 Update, Draft Results," presented to NEPOOL Markets Committee, August 7, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013/a04_brattle_group_presentation_08_07_13.ppt.

[31] As previously noted, there is a small deficit in aggregate payments to generators that reflects the shortage of reserves in relation to the total customer demand (reflecting both load and the reserve requirement).

[32] With each reserve shortage event, resources in aggregate face a deficit equal to the size of the reserve shortage (in MW) times the PPR.

[33] The option could also be specified so that the payoff varied with the balancing ratio in the same manner as the downward revenue adjustments vary with the balancing ratio.

Fourth, risks to operational performance can be mitigated through actions to increase the likelihood that the resource supplies output during reserve shortages. This could include actions to reduce forced outages and failures to respond to system operator dispatch requests, actions to reduce the likelihood of fuel supply disruptions (particularly for gas-dependent resources) and actions to increase the likelihood that the energy-limited resources (such as pumped storage) have energy available to supply. Of course, creating incentives for these sorts of actions is a fundamental purpose of FCM PI. Taking such actions can also mitigate some – but not all – FCM PI financial risk, since performance is determined in part by factors that are beyond the resource's control (e.g., factors that affect energy market offers, such as heat rates and non-fuel operating costs).

Fifth, ISO has proposed "stop loss" provisions as part of the FCM PI design. The stop loss mechanism limits a capacity supplier's exposure to financial losses by capping monthly losses. Stop loss provisions are not designed to eliminate the risk of losses, but to insure against extreme losses. By limiting insurance to more extreme circumstances, the stop loss mechanism maintains performance incentives until monthly losses become particularly large. Under the current proposal, the stop loss mechanism limits losses to individual resources at the difference between the FCA starting price ($15 per kW-month) and the FCA clearing price. For example, if the FCA clearing price was $4 per kW-month, then monthly losses for each resources would be capped at the resource's CSO times $11 per kW-month (i.e., $15 minus $4 per kW-month).

Finally, energy and ancillary service market prices tend to increase during reserve shortages that occur during peak (summer) conditions, which are likely to prevail during future reserve shortages under equilibrium conditions. Figure 4 reports the percentage difference between energy market prices on days with peak period reserve shortages against energy prices on comparable days (i.e., either days in the same month or the same week). Day-ahead prices increase by 26% (within week comparison) or 64% (within month comparison) during on-peak periods, and 7% or 21% during off-peak periods. On-peak real-time price increases are larger than on-peak day-ahead prices (151% for the within week comparisons and 100% for the within month comparisons), although market participant revenues are typically most dependent on day-ahead prices.

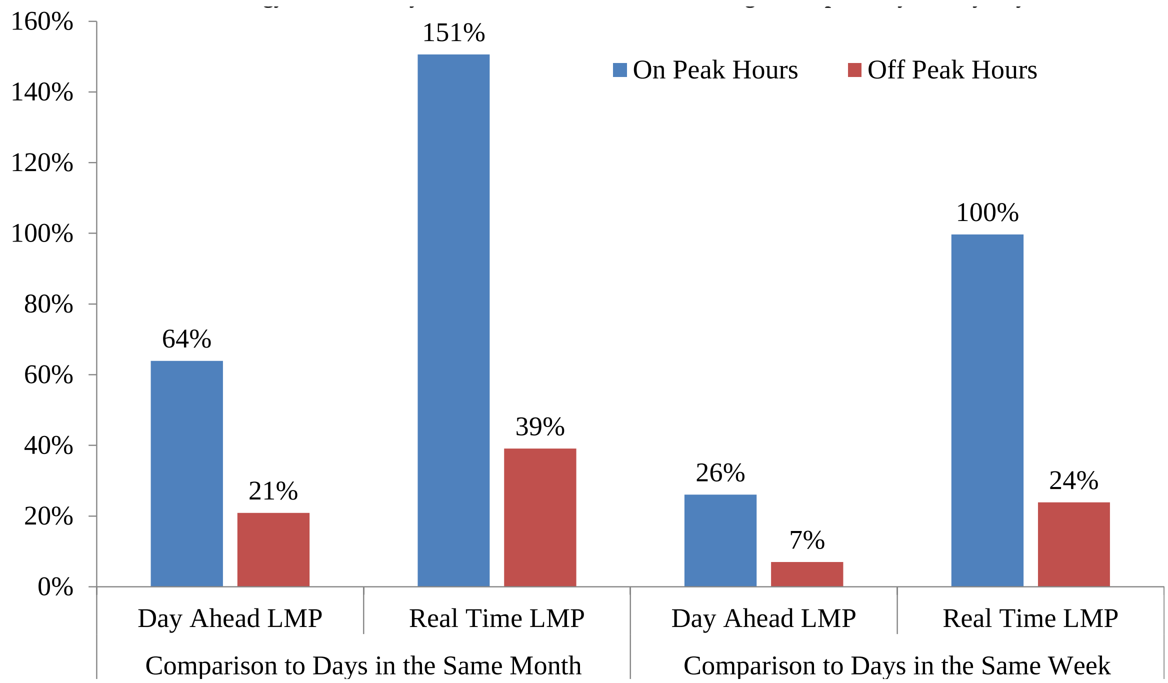
Given the uncertainty introduced by FCM PI in the FCM market, a risk factor is included in resource offers to reflect the resulting financial risk. In practice, the approach taken by individual market participants to estimate a risk factor to include in their offers will reflect many company-specific factors, including information that is often not publicly available. Given these information limitations and the complexities of performing company-level risk assessments for all entities in the ISO-NE market, certain simplifying assumptions are made.

In choosing an analytical approach for estimating the risk factor, it is important to keep in mind that economics and finance provide guidance on alternative ways of measuring financial risk, but do not conclude that there is a single optimal way to measure and manage financial risk. The analysis builds off the Value at Risk approach,[34] which is a standard approach used in the financial sector for valuing the

[34] Eydeland, Alexander, and Krzystof Wolyniec, *Energy and Power Risk Management, New Developments in Modeling, Pricing, and Hedging*, Wiley Finance: Hoboken, New Jersey. Berry, Romain, "Value at Risk: An Overview of Analytical VAR," J.P. Morgan Investment Analytics and Consulting.

financial risk associated with a portfolio of assets.[35] Under this approach, analytical models are used to measure the distribution of potential financial returns of a portfolio of assets. The Value at Risk (VaR) is then the maximum potential loss of the portfolio at a pre-specified confidence level. For example, a firm may estimate that the VaR for a given portfolio of assets is a loss of $2 million at the 5% level over the next month. This means that there is a 5% chance that this portfolio will lead to losses of $2 million or more. Given this information, the firm may adjust its portfolio to bring the risk within (potentially pre-determined) tolerance levels.

Figure 4: Average LMP Increase on Days with Peak Period Reserve Shortages



Note: Figures reflect only reserve shortage events that occurred during peak hours in June, July, or August 2010 - 2012.

Risk factors are calculated using the VaR approach in the following manner. For each resource, the risk factor equals the increase in a resource's offer needed to ensure, with a 95% probability, that it earns positive expected net revenues across all ISO-NE markets. The analysis only considers uncertainty in the level of reserve shortages, but not resource performance. Uncertainty over the level of reserve shortages creates meaningful financial risk, particularly for resources with poor performance. For poorly performing resources, each additional reserve shortage can result in financial losses because the unit's

[35] Other approaches to addressing financial risk include asymmetric (and potentially non-linear) valuation of losses and gains and requiring risk-adjusted returns (potentially reflecting the variance of potential losses). These models are grounded in certain fundamentals of financial analysis (including portfolio theory) but recognize certain costs to losses that may not be recognized in these models, including credit constraints (which may impose limits on the ability of a firm with poor credit from pursuing profitable business opportunities) and managerial risk aversion (which may be a fact of life given principal agent problems).

output is likely below the balancing ratio benchmark. Consequently, if the level of reserve shortages exceeds expectations, losses could grow large, even potentially leading to negative net FCM revenues.[36] By contrast, risks associated with resource performance are bounded by several factors. First, as shown in Figure 1, resource performance and the balancing ratio tend to be positively correlated. Thus, an element of performance uncertainty is addressed by the FCM PI design, which lowers the benchmark against which each resource's performance is compared during shortages when aggregate output is lower. Second, assuming actual reserve shortages equal expected levels, the minimum offer (essentially) provides sufficient revenue to avoid losses (negative net revenues).[37] Analysis that simultaneously considers uncertainty in both reserve shortage levels and operational performance was beyond the scope of our analysis.[38]

Based on uncertainty in reserve shortage levels, the risk factor is calculated as:

$$RF = \min\left\{0, GFC - P_{FCM} - PPR * H_{95\%} * \left(A - BR\right)\right\}$$

Here, $H_{95\%}$ is the reserve shortage level at the 95% confidence interval. This value is based on the probability distribution of future reserve shortages under different levels of excess resources from analysis performed with the ISO-NE system model. In effect, as shown in Figure 5, the risk factor shifts the distribution of total returns such that there is a 95% likelihood that the resource has positive net returns.

These VaR estimates reflect one approach to estimating resource risk factors, but may not consider all factors relevant to determining the risk factor for individual resources. For many resources, these risk factors will reflect conservative estimates of risk. For poor performing resources, the approach can result in tradeoffs between risk and expected returns suggesting that market participants are very risk averse.[39] On the other hand, for some market participants, the VaR approach may understate risk factors by assuming that they would be indifferent to the choice between a market position with and without a CSO that provides equal expected returns. It is quite likely that some market participants faced with these

[36] Even when actual performance equals the resource's expected performance, actual FCM revenues will be negative whenever the number of reserve shortage hours is greater than the ratio of the annual fixed FCM revenues (i.e., P_{FCM}) divided by the loss per hour of reserve shortage – that is: $H > \dfrac{P_{FCM}}{PPR * \left(BR - A\right)}$.

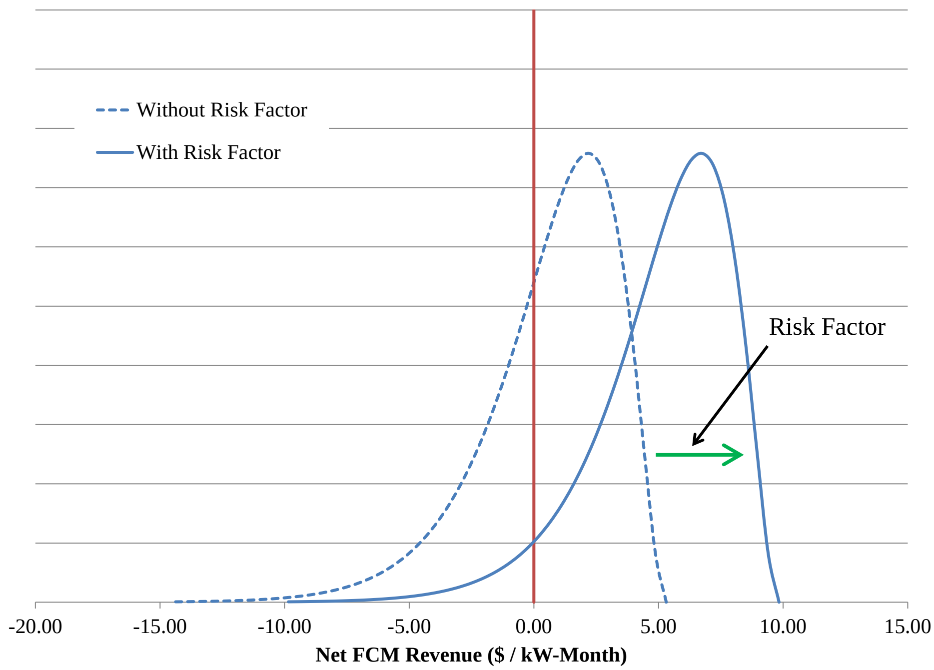
[37] With no uncertainty over H, the minimum offer is $PPR*H*BR$. So long as actual BR is no less than the expected BR, then the minimum offer exceeds the revenue adjustments for all levels of output. That is, $PPR * H * E\left[BR\right] + PPR * H * \left(A - BR\right) \geq 0$ for all levels of performance A as long as the actual average balancing ratio (BR) is less than the expected average balancing ratio ($E\ [BR]$).

[38] Such analysis would require Monte Carlo analysis that accounted for both reserve shortage and performance uncertainty, along with the relationship (correlation) between these factors, which would vary across individual resources.

[39] For example, consider a poorly performing resource (A = 0.1) with going forward cost of $1 per kW-month under the following market conditions: BR = 0.75, E[hours] = 12, $Hours_{95\%}$ = 25.2. This resource would have a risk factor equal to $3.57 per kW-month. A risk factor at this level suggests that the resource would prefer to forego a CSO and receive expected FCM revenues of $0.50 per kW-month from providing capacity without an obligation (reflecting performance incentive payments) rather than accept the CSO with expected returns of $4.57 per kW-month. This sort of tradeoff suggests a high degree of risk aversion on the margin.

two choices would require some risk premium to accept the financial option (contingent on the balancing ratio adjustments) that comes with a CSO under FCM PI. This type of preference is consistent with behavioral economics, managerial incentives, and certain corporate finance limits.[40] In practice the value of the FCM PI option will depend on each market participant's individual risk profile. Thus, our approach likely understates the quantity of resources that would opt to submit positive risk factors.

Figure 5: Illustrative Depiction of the Shift in Net Revenues with the Risk Factor



Risk factors also account for portfolio effects among resources owned by the same corporate entity. By considering these portfolio effects, the risk factor estimates account for hedging of risk across individual resources. For example, an entity with one high performing resource (typically receiving positive FCM revenues with every incremental reserve shortage) and one poor performing resource (typically receiving negative FCM revenues with every incremental reserve shortage) would face very different financial risks than an entity with only one poorly performing resource. To account for these portfolio effects, each resource's risk factor reflects the portfolio of resources that would clear if it were the marginal resource. Thus, for each resource, the risk factor reflects the marginal risk it adds to the portfolio of resources that would clear at or below its offer price.

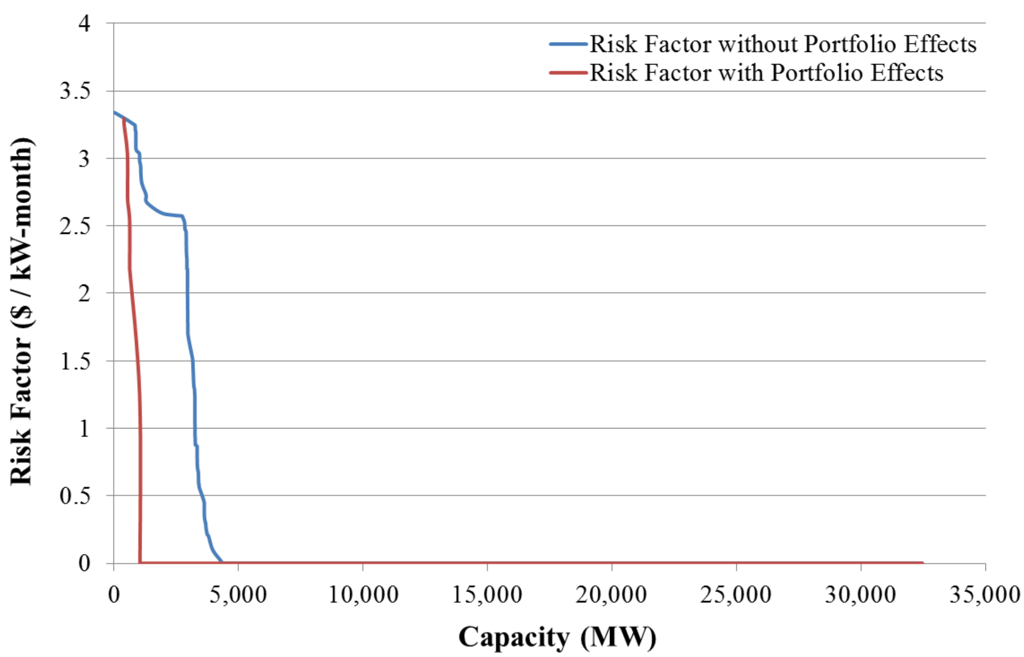
Because this approach accounts for only a limited set of factors, it may understate risks for some resources and overstate them for others. On the one hand, the analysis does not account for factors that would mitigate risks, including stop loss provisions and opportunities to hedge financial risks. On the

[40] For example, greater uncertainty can increase the risk that a firm faces circumstances in which it is credit constrained and potentially must forgo potentially profitable investments.

other hand, the analysis does not account for factors that would increase risk, including performance uncertainty and behavioral preference for more certain returns.

The resulting risk factors vary across scenarios. Figure 6 shows the risk factors for the Equilibrium: No Gas scenario. Without portfolio effects, about 4,300 MW of resources have positive risk factors, with the largest risk factor at nearly $3.50 per kW-month. Resources with positive risk factors include units with relatively low performance (below 40%) and some higher performing resources that rely on FCM revenues to remain economically viable (i.e., resources with positive GFC including FCM PI revenues). Financial risks are greater for resources with higher going forward costs because they have less financial cushion from other ISO-NE markets to ensure positive profitability. Accounting for portfolio effects reduces the quantity of resources with risk factors to about 1,000 MW, with a minimal change in the largest risk factor. After accounting for portfolio effects, resources with positive risk factors include those resources held by entities with few resources and some poorly performing units with high going forward costs held by entities with larger portfolios.

Figure 6: Risk Factors in Near-Term Equilibrium Scenario



VI. IMPACT OF PERFORMANCE INCENTIVES ON ISO-NE MARKET

A. Impact on Reliability

In principle, FCM PI has the potential to improve reliability through several mechanisms, including increases in the supply of resources in the ISO-NE energy markets, increased adoption of dual fuel capability, changes in the mix of resources toward higher performing resources, and improvements in the operational performance through changes in operating practices or other performance investments (e.g., ramping capability). The analysis quantifies many but not all of these impacts.

1. *Increase in Resource Supply*

The introduction of FCM PI can affect the quantity of resources that continue to participate in the ISO-NE energy market. As described in Section IV.A, if the expected level of reserve shortages is sufficiently high, then some resources that do not take on an FCM CSO may remain in ISO-NE's energy market in anticipation of additional FCM PI payments received for output supplied during reserve shortages. Under these circumstances, the quantity of resources in the ISO-NE energy markets can exceed ICR, which, in turn, results in improved reliability, including reductions in the level of reserve shortages.

Table 4 reports estimates of the difference between the total quantity of "economic capacity" and ICR, referred to as "surplus capacity." Surplus capacity includes all capacity with a CSO and any surplus capacity resources without a CSO that receive sufficient revenues to remain economically viable in the ISO-NE energy markets. Determination of which resources are economically viable (i.e., receive positive net revenues including all ISO-NE markets) reflects only the costs identified in Section V, but may not capture all relevant values affecting resource retirement decisions.[41] Under current market rules, the analysis finds that there is no surplus economic capacity – that is, at the clearing FCA price, only those resources receiving a CSO will find it economically profitable to remain in the market.

Table 4: Market and System Outcomes under Historical and Equilibrium Scenarios

		FCM PI, Historical Scenario			FCM PI, Near-Term Equilibrium Scenario		
	Current Rules (No FCM PI)	No Gas Shortages	Gas Shortages	High Gas Shortages	No Gas Shortages	Gas Shortages	High Gas Shortages
FCA Clearing Price ($/kW-month)	$1.31	$1.93	$2.55	$2.91	$3.76	$3.76	$4.49
Total FCM Payments ($bil)	$0.54	$0.80	$1.06	$1.20	$1.56	$1.56	$1.86
Avg FCM Payments ($/MWh)	$4.07	$5.99	$7.92	$9.01	$11.68	$11.66	$13.92
% Change Relative to 2012 Level	-57%	-36%	-15%	-4%	25%	25%	49%
New Entry Offers ($/kW-month)	$8.87	$8.67	$8.08	$7.49	$8.62	$8.09	$7.50
Surplus Capacity Above ICR (MW)	0	0	0	0	1,036	1,390	1,472
Expected Reserve Shortage Hours	21	-	-	-	9.00	10.00	12.75
Summer Peak RS Hours	21	-	-	-	9.00	7.00	6.75
Winter Gas-Related RS Hours	-	-	-	-	0.00	3.00	6.00
Incremental Dual Fuel Capacity (MW)	0	226	5,848	7,368	39	6,130	7,988

Note: For the Historical Scenario, Expected Reserve Shortage Hours are not reported as they do not reflect a consistent market-system equilibrium.

Under Historical system conditions, there is no surplus capacity as a consequence of FCM PI. Given the level of reserve shortages assumed in these Historical scenarios, incremental FCM PI revenues are insufficient to keep resources in excess of the ICR in the energy markets.

[41] Values not considered in our analysis include significant investments needed to maintain on-going operations and the option value to delay retirements given that revenue streams in future years could be sufficient to allow plant operation to be economically profitable.

In the near-term Equilibrium scenarios, surplus capacity ranges from 1,036 MW with no gas shortages to 1,472 MW with gas shortages (Equilibrium: High Gas). In these cases, more than 1 GW of resources in excess of the ICR would find it financially profitable to remain in operation in the energy markets, even without a CSO.

Table 4 also reports the expected number of reserve shortage hours given the level of surplus capacity in each scenario based on results from the ISO-NE system model. For the Equilibrium scenarios, there are 9.0 reserve shortages hours with no gas shortages, 10.0 total hours with gas shortages (3 hours) and 12.75 total hours with high has shortages (6 hours). These values equal the level of reserve shortages estimated when determining the market-system equilibrium based on the level of *summer peak* reserve shortages (as described in Section V.C). As higher levels of winter gas reserve shortages are assumed, the equilibrium level of total reserve shortages increases, which provides additional revenues for a larger quantity of surplus capacity. This higher level of surplus resources, then results in a lower level of *summer peak* reserve shortages. Thus, the level of summer peak reserve shortages declines as additional winter gas reserve shortages are assumed.

For the Historical scenarios, the values are not reported as they do not reflect a consistent market-system equilibrium.[42] Outcomes without FCM PI reflect the fact that under the current FCM model, the "economic" supply of resources equals ICR – that is, excess supply equals zero.[43] Thus, the expected level of reserve shortages is higher – 21 hours – because there is no surplus capacity. This outcome also corresponds to the long-term equilibrium in which new resources are needed to help meet future growth in ICR.

These results indicate that FCM PI would likely result in higher levels of reliability by increasing the quantity of resources participating in the ISO-NE markets. The improvements in reliability from this surplus capacity are reflected in the differences in the level of reserve shortages between the current FCM model (21 hours) and the Equilibrium scenario outcomes (9.0 to 12.75 hours). These reliability benefits would be experienced throughout the year, although they would be the most significant during summer peak load periods. Reliability risks associated with winter gas limitations would also benefit, to the extent that the surplus reflects resources that are not "gas dependent." Later sections address these factors in greater detail.

Our analysis considers resource outcomes for the 2018/2019 Commitment Period, but does not quantitatively assess outcomes in subsequent commitment periods. Thus, the length of time that surplus capacity remains under FCM PI is not estimated, although FCM PI could extend the period with surplus capacity under many plausible market outcomes. Thus, the reliability benefit of FCM PI found for the 2018/2019 Commitment Period could be further extended.

Eventually, as operating and investment costs for existing resources increase (or operating performance decreases), resources that are currently economically viable under FCM PI will retire. As

[42] That is, the market model assumes one level of reserve shortages but the resulting level of surplus capacity produces a different level of reserve shortages in the system model.

[43] In reality, some resources may continue to operate in the market due to variety of factors, including the option value to continuing operation in future years in anticipation of increases in future capacity or energy market prices. This suggests that, when accounting for these factors and option values, the quantity of resources with negative GFC costs (i.e., resources that require positive FCM revenues to remain financially viable) could exceed the ICR.

this occurs, the current surplus of capacity will diminish, leaving the region in need of new generation resources. However, while the long-run equilibrium under the current FCM rules tends toward a system in which the quantity of resources equals the ICR, under FCM PI, the incremental revenues (which can economically support existing resources and reduce offers from new entry, as discussed below) could result in a long-run with resources in excess of the ICR. At this point in time, FCM PI should be expected to provide the same or greater level of reliability, based on the 1-in-10 days loss of load expectation criterion used in setting the ICR.

2. *Actions to Improve Performance, including Adoption of Dual Fuel*

The opportunity to earn additional revenues during reserve shortages creates an incentive for resources to take actions to improve performance. Improved performance can be achieved through new investments (e.g., adding dual fuel capability, improving generation performance and lowering startup costs) and operational changes (e.g., improved maintenance to limit forced outages, increased pumping by pumped storage units, and improved systems to respond to system operator dispatch requests). To the extent that such actions are undertaken, they could result in improved reliability (including reductions in the level of reserve shortages), lower energy market costs and lower FCM prices.

The quantitative analysis assesses the extent to which resources that could face limited access to fuel supplies – gas-dependent resources – take steps to make their plants capable of burning an alternative fuel. With dual fuel capability these resources, which otherwise might lose revenues due to curtailed fuel supply, can continue operations during reserve shortages.

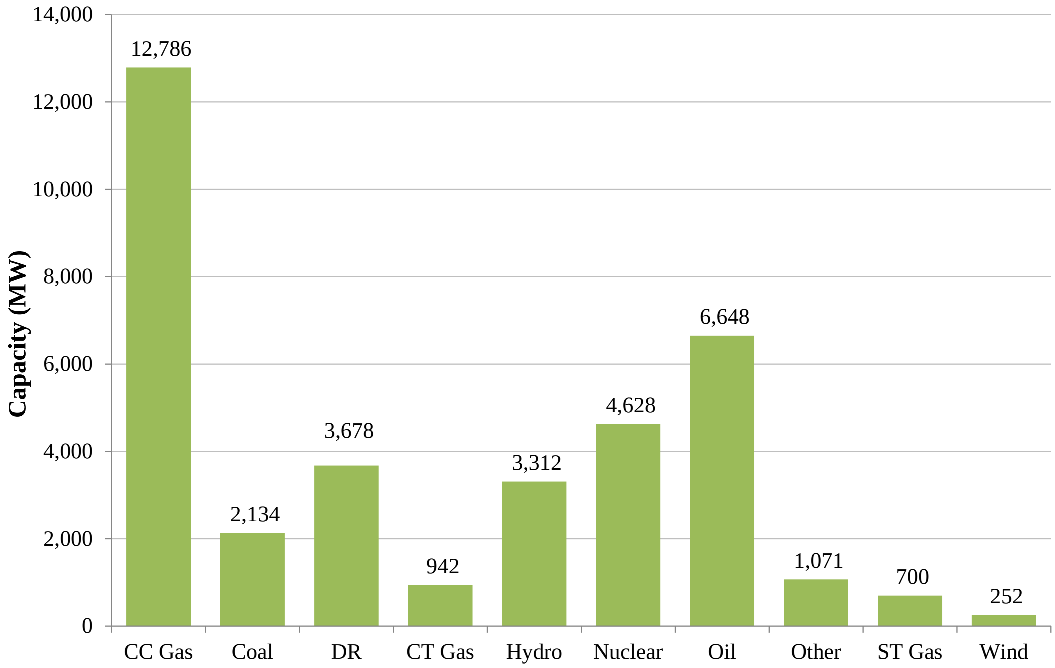
Figure 7 illustrates the mix of resources in the current ISO-NE fleet. Roughly 30% of the region's generation resources, or 10.1 GW out of 36.1 GW, are currently dependent solely on natural gas, with no option to operate on an alternative fuel. Today, roughly 6,600 MW of capacity has dual fuel capability, although this total has fallen from higher levels in recent years because the divergence of gas and oil prices has made oil combustion uneconomic.[44] As current market conditions do not support maintaining dual fuel capability (including maintenance of alternative fuel capabilities and storage of costly fuel supplies) for energy production, and there are currently no mechanisms for supporting dual fuel capability for reliability purposes, the supply of dual fuel capability has diminished over time.

The analysis indicates that the introduction of FCM PI would increase the supply of resources that are not subject to gas-dependency. Figure 8 illustrates these changes by highlighting both the quantity of dual fuel capability and the quantity of non-gas resources (which do not face gas curtailment risks) with and without FCM PI, under the Equilibrium scenarios. FCM PI would increase investment in dual fuel capability under conditions when market participants expect reserve shortages driven by limited gas fuel supplies. Without PI, there is 5,607 MW of dual fuel capability in the region. Under Equilibrium scenarios, dual fuel capability increases by 6,130 MW to 11,737 MW if 3 hours of winter gas shortages are assumed, and by 7,988 MW to 13,595 MW if 6 hours of winter gas shortages are assumed. Results are similar under the Historical scenarios, as shown in Figure 9. There is also a small increase in dual fuel capability (226 MW under Historical conditions and 39 MW under Equilibrium conditions) when no

[44] This total includes some resources that, in a past, tended to operate primary on non-gas fuels (primarily oil) that have switched largely to gas-fired operations in recent years.

winter gas shortages are expected because of shifts in the mix of "economic" resources with and without FCM PI.

Figure 7: Current ISO-NE Resource Mix (FCA 7)



Note: The figure lists only resources within the ISO-NE footprint, thus excluding imports that clear in FCA7.

These comparisons reflect the assumption that all existing dual fuel resources retain this capability under current market rules. Thus, our analysis does not account for the risk that owners of facilities with dual fuel capability opt to mothball this capability, as many resources have already done in recent years. By assuming that resources preserve dual fuel capability absent FCM PI, the analysis may understate FCM PI reliability benefits by failing to capture these potential losses of dual fuel capability. The analysis also assumes that the addition of dual fuel capability is the least-cost approach to mitigating gas curtailment risks, as discussed in Section V.D. To the extent that there other options that can provide this mitigation at lower cost, then the analysis would also tend to understate the reliability benefits of FCM PI.

In addition to these increases in dual fuel capability, FCM PI results in small increases in the quantity of non-gas resources that help maintain reliability in periods of limited gas supply. Without FCM PI, there are 19,304 MW of non-gas resources in the Equilibrium scenarios. With the introduction of FCM PI in the Equilibrium scenarios, the quantity of non-gas resources increases to 19,803 MW, without assuming any winter gas reserve shortages. When winter gas reserve shortages are assumed, the quantity of non-gas resources increases by another 452 MW with 3 winter gas reserve shortage hours and 534 MW with 6 hours.

Figure 8: Gas Dependency Resource Changes, Equilibrium Scenarios

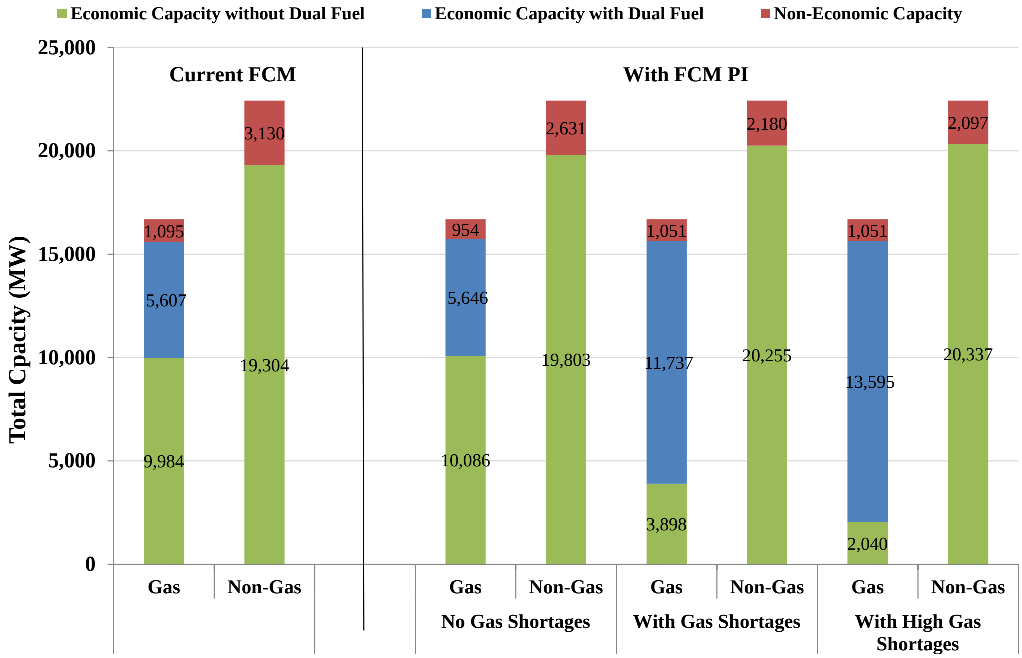
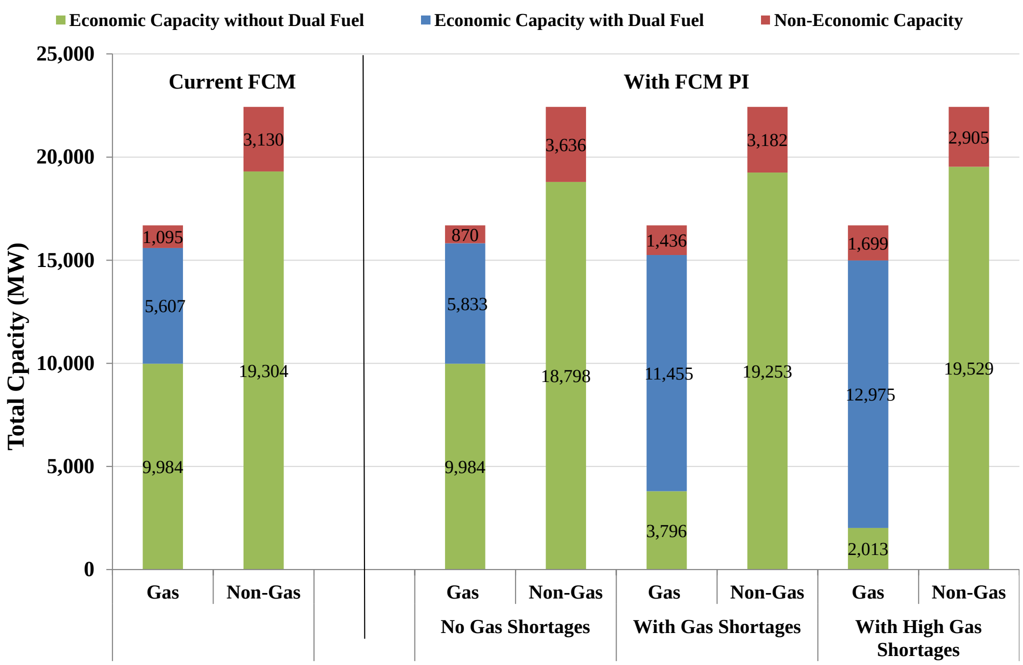


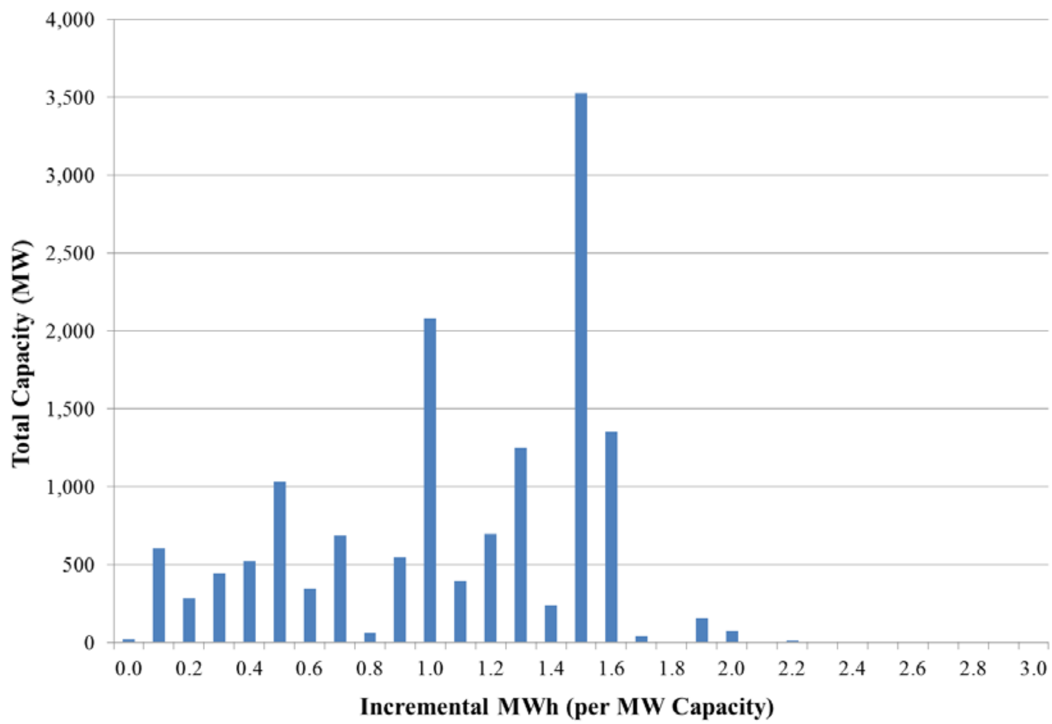
Figure 9: Gas Dependency Resource Changes, Historical Scenarios



Notes for Figures 8 and 9:
[1] Dual Fuel Gas Capacity includes some units listed in the 2013 CELT Report with a primary fuel type of RFO or DFO that currently have dual fuel capability.
[2] Oil units based on primary fuel use from 2013 CELT Report, but may include units that have used gas as a primary fuel in recent years.

For each gas-dependent resource, the financial gains from adopting dual fuel capability reflect the incremental MWh of output that can be supplied during winter reserve shortages from having addressed the unit's gas curtailment risks. Figure 10 illustrates the distribution of operational benefit of maintaining dual fuel capability for all gas-fired resources, as reflected by the incremental MWh supplied during winter gas reserve shortages, for the Equilibrium: Gas scenario (i.e., 3 hours of reserve shortages). For example, consider a 100 MW resource with "Incremental MWh per MW of Capacity" equal to 1.6 MWh over the three hours of additional winter reserve shortages. This unit would receive an additional 160 MWh of output by investing in dual fuel capacity; over one year, assuming a PPR of $5,455, this resource would receive an additional $872,800 in revenues. The figure shows that even though there are 3 additional hours of reserve shortages, our approach results in relatively modest assumptions about the additional MWh of output that market participants would gain from investing in dual fuel.

Figure 10: Distribution of Incremental MWh (per MW of Capacity) during Winter Reserve Shortages, Gas Shortage Scenario (3 Hours)



These results are particularly sensitive to assumptions about cost. As shown in Figure 3, portions of the dual fuel supply curve are relatively flat, which could lead to large variation in the quantity of dual fuel upgrades depending on the magnitude of performance incentives. To determine whether this affects estimated outcomes, a sensitivity analysis is performed in which dual fuel costs (including both upfront capital and annual expenditures) are increased by 25%. The results of this scenario are reported in Table 5. When costs are increased by 25%, the quantity of dual fuel upgrades increases under FCM PI by 2,985 MW with 3 hours of gas shortages, and by 7,484 with 6 hours of gas shortages. Thus, dual fuel upgrades from FCM PI decrease by over 50% when costs are increased by 25% with 3 hours of winter reserve shortages. By contrast, dual fuel upgrades decrease by only 6% at the higher level of winter reserve shortages (6 hours). These results suggest that there is substantial uncertainty about the level of dual fuel upgrades at moderate levels of gas dependency risks, but less uncertainty when these risks become sufficiently high.

Table 5: Market Outcomes for Dual Fuel Cost Sensitivity Analysis

		Baseline Costs		Baseline Costs + 25%	
	Current Rules (No FCM PI)	FCM PI Gas Shortages	FCM PI High Gas Shortages	FCM PI Gas Shortages	FCM PI High Gas Shortages
FCA Clearing Price ($/kW-month)	$1.31	$3.76	$4.49	$3.76	$4.49
Total Dual Fuel Capacity (MW)	5,607	11,737	13,595	8,592	13,091
Change in Capacity from No FCM PI	-	6,130	7,988	2,985	7,484

The results indicate that FCM PI can increase reliability by improving the quality of resources participating in ISO-NE markets. The analysis shows that resources that would otherwise face no incentive to develop dual fuel capability would choose to develop this capability under FCM PI when market participants anticipate meaningful system reliability risks associated with gas-supply curtailment. However, the analysis does not identify a final equilibrium between the quantity of dual fuel upgrades and the level of reliability (as reflected in reserve shortages) given gas dependency risks. As with the equilibrium between the level of total system resources and summer peak reliability, this eventual equilibrium will depend on the dynamic between these two factors. As the quantity of dual fuel upgrades increases, reliability risks associated with gas-dependency will improve; however, as winter gas reliability improves (and reduces the level of reserve shortages), revenues to support dual fuel upgrades will decrease. Thus, the analysis does not resolve uncertainty about the final level dual fuel upgrades and winter gas reliability under FCM PI.

The quantity of incremental dual fuel capability developed rises as high as 7,988 MW under the "worst case" expectations evaluated (i.e., 6 hours of winter gas reserve shortages under Equilibrium conditions). Because all but roughly 2 GW of gas-fired resources would upgrade to dual fuel under this scenario, the underlying reliability risks driving these winter gas reserve shortages would likely be fully mitigated. This suggests that an "equilibrium" level of gas reserve shortages and additional new dual fuel capability could be below the levels assumed in this "worst case" scenario. This conclusion is further supported by the fact that FCM PI would provide additional incentives for resources relying on on-site fuel supplies (particularly oil-fired resources and existing dual fuel resources) to maintain higher levels of on-site stored fuel, which could mitigate reliability risks associated with prolonged and sequential episodes of gas supply limitations.

While the results of this "worst case" scenario suggest that FCM PI would provide sufficient incentives to mitigate gas dependency risks, the analysis does not identify a precise equilibrium level of dual fuel upgrades and winter gas reliability. Moreover, the sensitivity of the quantity of dual fuel upgrades to assumptions about underlying upgrade costs highlights the substantial uncertainty about the eventual equilibrium levels of incremental actions taken to mitigate winter gas curtailment risks (including dual fuel) and winter gas reliability (as reflected in reserve shortage hours) when winter gas dependency risks are at levels more moderate than the "worst case" scenario.[45]

3. Change in Mix of Economic Resources in ISO-NE Markets

The introduction of FCM PI is intended to create incentives for higher performing resources to compete more effectively against lower performing units. With these incentives, resource entry (new build) and exit (retirement) decisions should result in a mix of higher performing resources in the long run as these retirement and new build decisions are made. The analysis of outcomes in FCA 9 and impacts on the cost of new entry can provide insights on the extent to which these incentives have meaningful effects on these decisions.

The introduction of FCM PI has several effects on the mix of available resources. These effects are illustrated in Table 6, which reports the mix of "economic" resources with and without FCM PI under the Equilibrium: No Gas Scenario, as well as Figure 11, which shows "non-economic" capacity by resource type for the Equilibrium: No Gas and Historical: No Gas scenarios. As discussed above in Section VI.A.1, the total quantity of economic resources is expected to be greater under FCM PI than under current FCM rules. Despite this aggregate increase, the quantity of oil-fired resources decreases with FCM PI. Figure 11 shows that the quantity of "non-economic" oil-fired capacity increases from 1,047 MW to 2,282 MW in the Equilibrium: No Gas scenario, suggesting an increased likelihood of retirement of oil-fired resources under FCM PI. By contrast, the quantity of all other resource types increases under FCM PI compared to current rules. Demand response and imports (combined) increase by 1,407 MW in the Equilibrium: No Gas scenario, while there is combined increase of 476 MW between gas-fired resources (CC Gas, CT and ST Gas) and coal-fired resources. These changes to the resource mix are generally supportive of reliability, as they result in a larger supply of more flexible resources, including fast start and demand response, and a reduced supply of slower fossil units, such as oil units.

As seen in Table 6, performance varies across resource categories, and the average performance masks variation among the units within individual categories. Variation in performance reflects operational factors (e.g., forced outages) and economic factors (e.g., heat rates, start-up costs and other factors that affect resource energy market offers). For existing resources, market participants have some control over these factors and limited control over others.

Table 6 also illustrates that under FCM PI, resource performance (as measured by average performance *A*) tends to increase for certain generator categories compared to current rules. These shifts in performance reflect two offsetting factors. The first arises from the fact that more economic resources remain in the market with FCM PI than without. Because marginal resources will tend to have poorer performance than resources that remain in the market, under any scenario, the *average* performance will tend to decrease as the quantity of surplus resources increases simply because the last resources added tend to have lower performance. This effect would tend to result in *lower* average performance under FCM PI, because it supports a larger pool of resources.

[45] This sensitivity mirrors the uncertainty underlying other assumptions, including the level of gas curtailment risk that resources would face during winter gas-related reserve shortage, which was set at a 50% reduction in output without dual fuel capability to balance the range of curtailments that resources could face.

Table 6: Resource Mix and Average Performance With and Without FCM PI, Equilibrium: No Gas Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,717	100%	791	100%
Renewables	4,698	112%	7	4%
Nuclear	4,628	105%	0	NA
CC Gas	12,712	91%	74	22%
Coal	1,703	86%	431	90%
CT or ST Gas	1,642	89%	0	NA
Oil	4,366	66%	2,282	14%
Other	1,070	91%	0	15%
Total	35,536		3,585	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	112%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,470	92%	315	70%
Coal	1,591	85%	543	93%
CT or ST Gas	1,520	89%	122	91%
Oil	5,601	54%	1,047	39%
Other	1,071	91%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

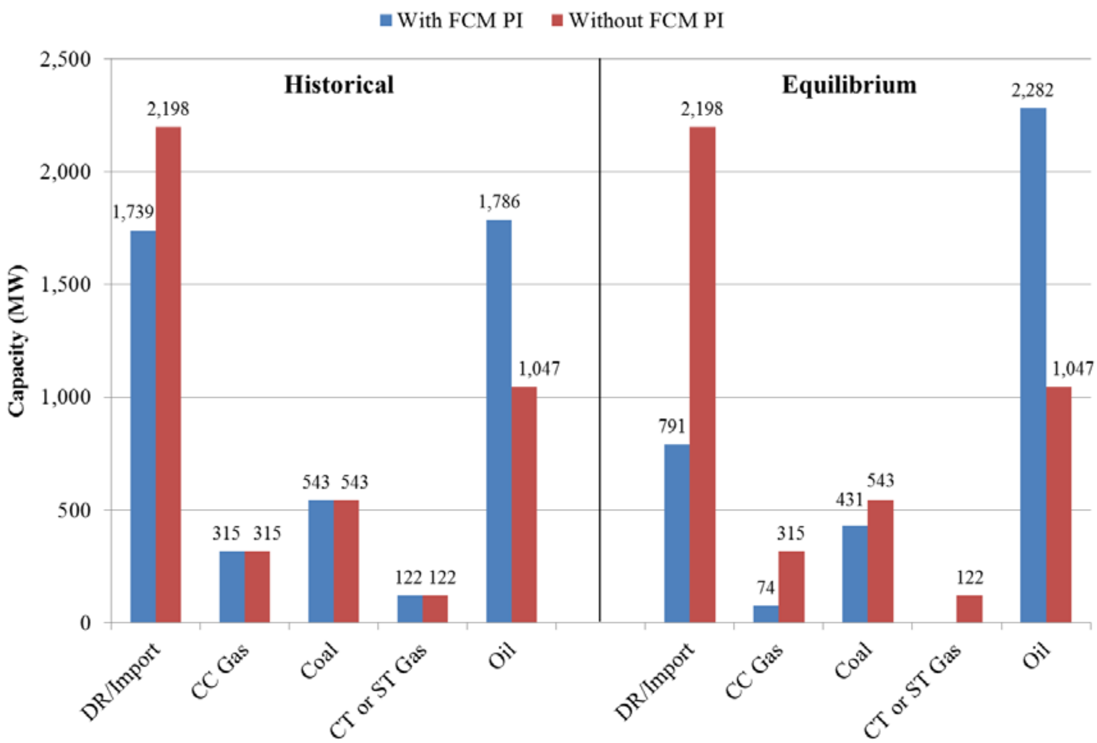
	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,407	0.0%	-1,407	0.0%
Renewables	-7	0.2%	7	NA
Nuclear	0	0.0%	0	NA
CC Gas	241	-0.1%	-241	-48%
Coal	113	1.3%	-113	-3%
CT or ST Gas	122	0.1%	-122	NA
Oil	-1,235	12%	1,235	-25%
Other	0	0.0%	0	NA

Notes:
[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.
[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).
[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine
ST: Steam Turbine.

However, FCM PI also results in shifts among resources that are economic, with higher performing resources clearing due to PI, and lower performing resources becoming non-economic. This effect would tend to result in higher average performance with FCM PI.

As shown in Table 6, the effect of FCM PI on average performance tends to outweigh the effect of the higher quantity of resources, suggesting that these incentives would likely have a positive effect on improving the average performance of resources in the region. For all resource categories but CC Gas, average performance increases with FCM PI. The improvement in performance is most notable with oil-fired resources, which have performance of 66% with FCM PI and 54% without FCM PI.

Figure 11: Non-Economic Capacity by Technology/Fuel Type with and without PI, Historical and Equilibrium (No Gas) Scenarios



Changes to the resource mix introduced by FCM PI under the Historical: No Gas scenario have similar effects to those for the Equilibrium: No Gas scenario, as shown in Figure 11. Under the Historical scenario, there is no surplus economic capacity because the level of FCM PI revenues is reduced with the lower level of expected reserve shortages.[46] Non-economic capacity is higher in the Historical scenario for all resource types except oil-fired capacity. Under historical conditions, there are fewer non-economic

[46] The small quantity of capacity in excess of the ICR in the Historical scenarios and the scenario with no FCM PI arises because only a fraction of the marginal resource is required to meet the ICR. Because our model assumes that a portion of a unit cannot retire, the remaining fraction of the marginal resource is assumed to remain in the market.

oil-fired resources because the performance incentive payments are lower, which in turn reduces the competitive disadvantage that the oil-fired resources with lower performance experience under FCM PI.

Detailed tables for other scenarios are provided in Appendix B, which illustrates the change in resource mix when there are winter gas reserve shortages. As the level of winter reserve shortages increases, the changes in the resource mix introduced by FCM PI tend to be similar across scenarios, although the quantity of non-economic oil-fired resources increases with high gas-related reserve shortages. Although a higher level of winter gas reserve shortages could create financial risks for gas-dependent resources, the ability to develop dual fuel capability provides these resources with an option to mitigate this financial risk to maintain economic operations. Thus, the quantity of economic gas-fired capacity remains unchanged as the level of winter gas reserve shortages increases.

Our analysis does not account for actions resources can take to improve operating performance aside from the opportunity for gas-dependent resources to invest in dual fuel capability. These potential actions range from investments to improve operating efficiency (e.g., heat rates) and ramp rates to improved management and maintenance to reduce forced outages.

The results indicate that FCM PI can improve reliability through shifts in the mix of resources toward more flexible types and toward higher performing resources within individual resource categories. While the analysis captures these changes in performance, it does not provide any information on the technical or operational factors that lead to varying average performance across units in the ISO-NE fleet, or the factors that tend to affect the ability of resources to operate profitably in the ISO-NE markets.

B. Impact on Costs

FCM PI has several potential impacts on costs. In principle, FCM PI can lower production costs if shifts in the mix of resources results in a fleet of resources with higher operating efficiencies (e.g., lower heat rates). Statistical analysis indicates that there is typically a correlation between higher performing resources and more efficient resources, which suggests that FCM PI could contribute to increasing the operating efficiencies of resources in the region's fleet.[47]

FCM PI will also result in additional expenditures, as resources take additional steps to improve performance. As gas-dependent resources invest in dual fuel capability, they will incur both upfront capital costs and annual operating costs. In the Equilibrium: Gas scenario (3 hours winter reserve shortages), upfront capital investment is about $310 million and incremental annual expenditures are $31 million for 6,130 MW of new dual fuel capability. In the Equilibrium: High Gas scenario (6 hours of winter reserve shortages), upfront capital investment is about $462 million and incremental annual expenditures are $46 million for 7,988 MW of new dual fuel capability. These costs reflect the upward sloping supply curve in Figure 3, which results in higher costs for the additional dual fuel capability added when the level of winter gas reserve shortages increases from 3 to 6 hours.

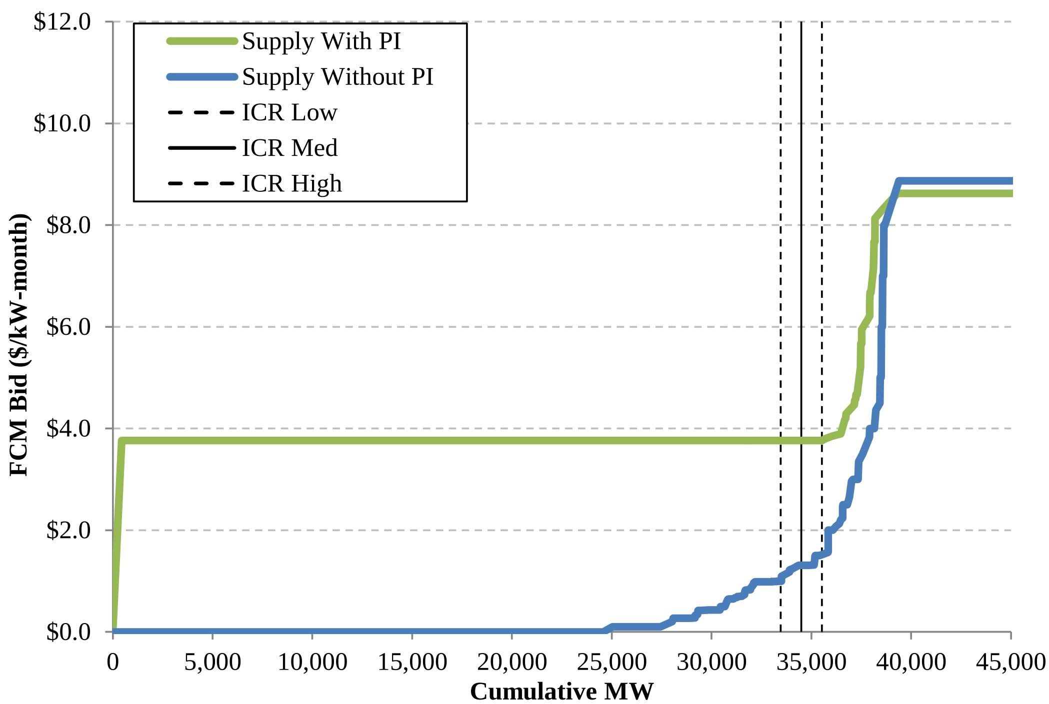
[47] Analysis of the correlation between average performance and heat rate for five resource categories across each of the three types of reserve shortages (historical, peak summer, winter gas) found a negative correlation for 11 of 15 tests, with oil-fired resources showing a positive correlation over all three types of reserve shortages.

Although not an element of our quantitative analysis, FCM PI could delay the date when new generation resources are needed to meet the ICR. Such delays could arise because the additional PI revenues can delay the retirement date for some resources, thus extending the operating lifetime of the region's current resource surplus further into the future.[48] By delaying the date at which new generation resources are required, FCM PI can lower resource costs. Because our analysis quantitatively evaluates outcomes only for 2018/2019, we do not estimate the likelihood that FCM PI delays new investment needed to meet the ICR, the length of such days or the associated cost savings.

C. Impact on Prices and Payments

The introduction of FCM PI will have both direct and indirect effects on many ISO-NE markets, including energy, ancillary services and capacity markets. Figure 12 illustrates the supply of offers from FCM resources with and without FCM PI in the Equilibrium: No Gas scenario. The introduction of FCM PI results in several shifts to the offer curve, including: an upward shift to minimum offers (reflecting the downward FCM PI revenue adjustments for the balancing ratio, $PPR * CSO * BR$), an upward shift in offers from many "marginally economic" units which tend to have relatively poor performance; and a downward shift to the cost of new entry, reflecting performance A greater than the balancing ratio for new resources. At the anticipated ICR of 34,500 MW for 2018/2019, the market clearing prices are $3.76 per kW-month with FCM PI and $1.31 per kW-month without FCM PI.

Figure 12: FCM Offer Curve with and without PI, Near-Term Equilibrium, No Gas Conditions



[48] FCM PI incentives could also induce new resources to enter the market at prices below the cost of new entry under conditions when there is surplus capacity above the ICR.

Table 4 reports the clearing prices for the other scenarios evaluated. Across the six scenarios, the clearing price without FCM PI remains unchanged ($1.31 per kW-month) because variations in the level of reserve shortages have no impact on FCA offers without FCM PI. However, with FCM PI, offers change to reflect anticipated FCM PI revenues. Under Historical scenarios, prices are lower due to the lower level of reserve shortages. This difference is best seen by comparing the scenarios with no gas shortages, with FCA prices at $1.93 per kW-month under historical conditions, and $3.76 per kW-month under near-term equilibrium conditions. Under historical conditions, FCA prices rise with the addition of winter gas reserve shortages hours to $2.55 per kW-month (6.2 total reserve shortage hours) and $2.91 per kW-month (with 9.2 total reserve shortage hours). Under equilibrium conditions, FCA prices vary across scenarios from $3.76 per kW-month to $4.49 per kW-month for the two approaches to modeling the high gas scenario equilibrium.

While FCM PI increases FCA offers for most existing resources, offers from new resources could decrease with the introduction of FCM PI if anticipated performance exceeds the balancing ratio. Whether this occurs, in practice, will depend on project developers' expectations about the performance of proposed projects, given various technological, operational and geographic factors. Moreover, FCM PI is designed to encourage development of those new resources with high performance.

To gauge the potential effect of FCM PI on the FCA offers from new entry, a benchmark group of gas-fired combined cycle and combustion turbine generation facilities recently developed in the ISO-NE region was chosen to represent new resource performance. The average performance of each group of resources was used to estimate the impact of FCM PI on the FCA offers from new entry for each technology. As shown in Table 7, which reports the offers from new combined cycle and combustion turbine technologies, FCM PI would likely reduce FCA offers from new resources below the cost of new entry (CONE) under current market rules, reflecting average performance by the benchmark group that exceeds the average balancing ratio in most cases.[49]

Table 7: Offers from New Entry with and without FCM PI

		FCM PI, Historical Scenario			FCM PI, Near-Term Equilibrium Scenario		
	Current Rules (No FCM PI)	No Gas Shortages	Gas Shortages	High Gas Shortages	No Gas Shortages	Gas Shortages	High Gas Shortages
Combined Cycle	$8.87	$8.67	$8.08	$7.49	$8.62	$8.09	$7.50
Combustion Turbine	$13.42	$13.34	$13.02	$12.70	$13.55	$13.20	$12.88

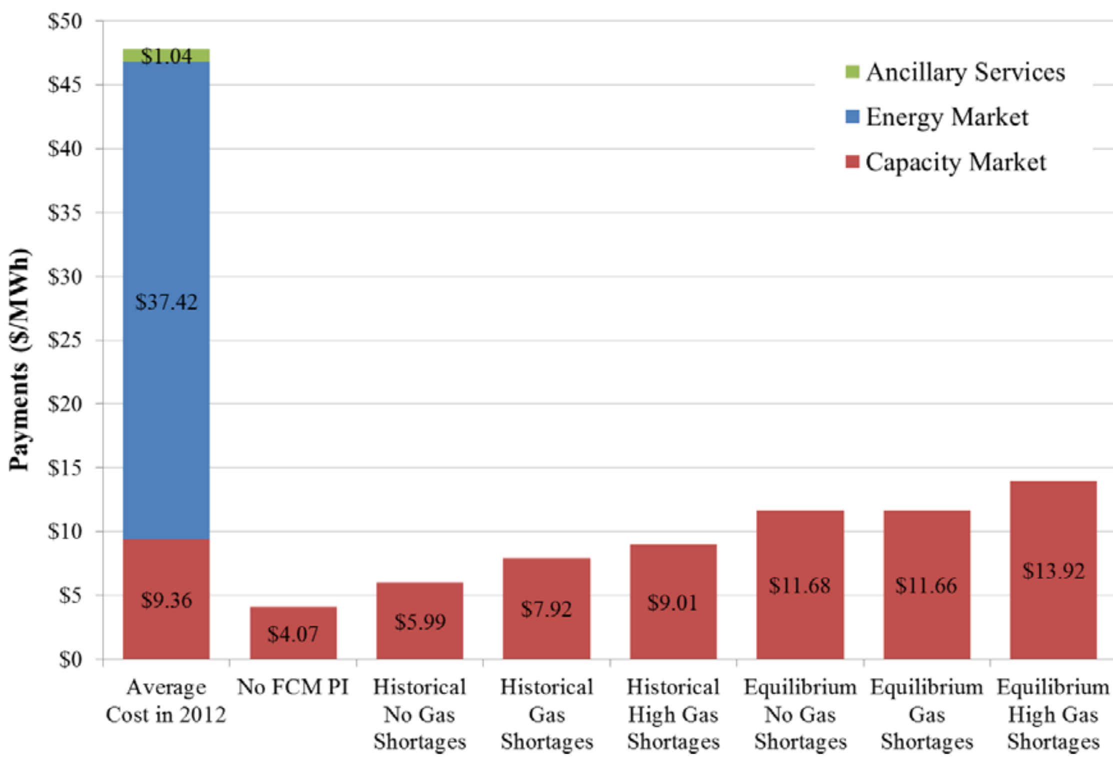
As shown by the scenarios with no gas shortages, when future reserve shortages are driven largely by summer peak conditions, the adjustments tend to be relatively small. However, when future reserve shortages are driven by winter gas supply limitations, the adjustments tend to be relatively large, reflecting the fact that performance of these flexible resources tends to be high during tight winter gas periods. For example, for a new combined cycle unit in the near-term equilibrium, these adjustments are $1.37 per kW-month in the Equilibrium: High Gas scenario. Because the level of adjustments in these Equilibrium scenarios reflects a level of reserve shortages with over 1 GW of surplus capacity, downward

[49] This conclusion does not reflect any adjustments due to financial risk.

adjustments in subsequent years (or the long-term equilibrium) could be greater as the quantity of surplus capacity decreases, and the expected level of reserve shortages increases.

Payments by load follow changes in FCM prices. Consequently, the introduction of FCM PI increases aggregate payments and payments per MWh compared to current rules. Figure 13 shows payments per MWh with and without FCM PI, and also compares these to current payment levels (as reflected in average 2012 payments). Compared to 2012 FCM payments, which reflect the administratively set price floors,[50] payments with FCM PI are lower than current levels under the Historical scenarios (by 4% to 36%, as shown in Table 4), but are higher than current levels under the Equilibrium scenarios (by 25% to 49%). When measured relative to all wholesale electricity market payments, these changes represent an even smaller fraction. For example, under the Equilibrium: No Gas Scenario, FCM payments are $11.68 per MWh with FCM PI compared to $9.36 per MWh in 2012. While this reflects a 25% increase in FCM payments, this increase is only 5% of total 2012 wholesale energy payments (of $47.82 per MWh).

Figure 13: Customer Payments Under Various Market Rules and Scenarios



Changes in energy market payments will arise due to changes in the quantity and mix of resources participating in the ISO-NE markets. These impacts are not quantitatively analyzed, although several observations can be made. First, when FCM PI results in surplus capacity above the ICR, this capacity would likely lower energy market prices, all else equal. The magnitude of this effect will depend

[50] This reflects the prorating of capacity supply obligations.

on energy market offers from those resources that remain in ISO-NE markets that would otherwise have exited the market, absent FCM PI. Surplus capacity will also diminish the level of reserve shortages, which in turn reduces RCPF payments. A simplified calculation indicates that the reduction in RCPF payments could range from $63 to $265 million.[51]

Second, to the extent that FCM PI encourages participation of higher performing units, including units with more competitive heat rates, then this greater performance would flow through to customers in lower energy market prices.

The results indicate that FCM PI would likely raise FCA prices under most circumstances when prices clear below the cost of new entry. However, FCM PI would likely lower offers from new entry due to the incremental revenues provided under FCM, particularly as these resources are likely to (and under FCM PI have incentives to) be high performing resources. Increases in FCM payments under the equilibrium scenarios (relative to 2012 levels) would reflect a 5% to 10% increase in 2012 wholesale energy payments.[52]

D. Sensitivity to Model Assumptions

The analysis of FCM PI relies on many modeling assumptions. To test the robustness of model results, in this section, we consider the sensitivity of results to three modeling assumptions:

1. Risk factors
2. Environmental costs
3. Restrictions on incremental dual fuel capability for new resources

Tables 8 to 10 report the results of these sensitivities. Each scenario is evaluated under near-term Equilibrium conditions. In general, conclusions about the impact of FCM PI do not change materially as a consequence of changes to the assumptions tested.

[51] This calculation assumes: reserve shortages levels reported in Table 4; load of 20,000 MW during winter gas reserve shortages and 26,000 MW during summer peak reserve shortages; and RCPF values of either $250 per MWh (for 30-minute local reserves) or $850 per MWh (for 10-minute system reserves). The reduction in payments ranges from $62.6 to $78.0 million at the $250 per MWh RCPF, and $212.9 to $265.2 million at the $850 MWh RCPF across the range of reserve shortage hours used in the Equilibrium scenarios.

[52] This reflects an increase in FCM payments of $2.30 per MWh (Equilibrium: Gas) and $4.56 per MWh (Equilibrium: High Gas) relative to a total payment of $47.82 per MWh.

Table 8: Market Outcomes for Risk Factor Sensitivity Analysis

	With Risk Factors		Without Risk Factors
	Current Rules (No FCM PI)	FCM PI	FCM PI
FCA Clearing Price ($/kW-month)	$1.31	$3.76	$3.76
Total FCM Payments ($bil)	$0.54	$1.56	$1.56
Avg Payments FCM ($/MWh)	$4.07	$11.68	$11.68
% Change Relative to 2012 Level	-57%	25%	25%

As seen in Table 8, elimination of the risk factor results in no change in outcomes for the Equilibrium: No Gas Scenario. This result arises because eliminating the risk factor does not change either the marginal unit that clears the FCM (which could occur if the risk factors affected the order of resource offers in the offer curve), or the offer of the marginal unit offer. Thus, although many resources incorporate a risk factor into their offers (as shown in Figure 6), risk factors do not affect the clearing price. .

Table 9: Market Outcomes for Environmental Cost Sensitivity Analysis

	Without Environmental Costs		With Environmental Costs	
	Current Rules (No FCM PI)	FCM PI	Current Rules (No FCM PI)	FCM PI
FCA Clearing Price ($/kW-month)	$1.31	$3.76	$2.00	$4.17
Total FCM Payments ($bil)	$0.54	$1.56	$0.83	$1.73
Avg Payments FCM ($/MWh)	$4.07	$11.68	$6.20	$12.95
% Change Relative to 2012 Level	-57%	25%	-34%	38%

The introduction of costs to comply with environmental regulations (Section §316(b) regulation of cooling water intake structures) increases the FCA clearing prices with and without PI. As shown in Table 9, under current market rules, FCA prices increase from by $0.69 per kW-month (from $1.31 per kW-month to $2.00 per kW-month) due to the higher FCA offers submitted by resources that need to comply with these regulations. Under FCM PI, FCA prices increase by $0.41 per kW-month (from $3.76 per kW-month to $4.17 per kW-month). Thus, FCM PI has a relatively similar impact on FCA clearing prices with and without the additional environmental costs.

Table 10: Market Outcomes for Dual Fuel Restrictions Sensitivity Analysis

	Equilibrium, High Gas		
	Current Rules (No FCM PI)	FCM PI	FCM PI Restricted DF
FCA Clearing Price ($/kW-month)	$1.31	$4.49	$4.49
Total FCM Payments ($bil)	$0.54	$1.86	$1.86
Avg Payments FCM ($/MWh)	$4.07	$13.92	$13.92
% Change Relative to 2012 Level	-57%	49%	49%

The last sensitivity evaluates how limits on the ability of gas-dependent resources to develop dual fuel capability affect market outcomes. Such limits could occur due to a variety of factors, such as restrictions on environmental permits needed to burn alternative (non-gas) fuels. To evaluate these impacts, dual fuel adoption is limited to those facilities with dual fuel capability that is currently decommissioned. Table 10 shows that, under Equilibrium: High Gas conditions, FCA prices with PI remain unchanged at $4.49 per kW-month with the dual fuel restrictions. Thus, the restrictions do not affect FCA prices. However, with these restrictions, the quantity of dual fuel resources falls from 13,595 MW to 8,906 MW, a reduction of 4,689 MW. Thus, while restrictions on dual fuel capability may not affect the FCA price, they could affect the reliability benefits achieved by FCM PI.

VII. EVALUATION OF OTHER OPTIONS

Our analysis considers an alternative proposal, offered by NRG, to ISO-NE's proposed FCM PI.[53] ISO-NE identified this alternative for evaluation, in part, because it was developed in sufficient detail early enough in the stakeholder process that it could be analyzed in the context of the initiative proposed by ISO-NE. This proposal includes multiple elements, which we describe below.[54] Following these descriptions, we provide quantitative and qualitative assessment of this alternative in comparison to FCM PI.

A. NRG Alternative

NRG has proposed an alternative to FCM PI that includes several elements.[55]

[53] Although other stakeholders offered alternative proposals, ISO-NE viewed these proposals as insufficiently developed to warrant detailed quantitative analysis.

[54] NRG, "FCM Performance Incentives – An Alternative Proposal," November 16, 2012; Fuller, Pete, NRG, "Market Reform Proposal," NEPOOL Markets Committee, August 7, 2013. Available at http://www.iso-ne.com /committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov162012/a02_nrg_alternative_proposal_11_16_12_ .pdf and http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013 /a10d_nrg_presentation_08_07_13.ppt.

[55] NRG also proposed certain changes to market rules regarding the type of costs that can be included in FCA offers for existing resources. We did not evaluate these changes because they were considered outside the scope of analysis appropriate for the Impact Assessment.

First, current RCPF's would be increased by $5,455 per MWh above current levels. Thus, energy market prices could rise as high as $6,305 per MWh during reserve shortages.[56]

Second, the Peak Energy Rent (PER) Adjustment would be eliminated. Current FCM rules include a PER Adjustment that reduces FCM payments whenever prices exceed a predetermined price threshold. By eliminating the PER Adjustment, the change in RCPFs results in changes in energy market revenues that are not also offset by subsequent PER Adjustments (which are fixed for each MW of capacity). However, these additional energy revenues streams would affect each unit's going forward cost, which in turn would result in reductions in FCM offers. Consequently, under the NRG Alternative, these PER Adjustments would be eliminated.[57]

Third, an "EFOR-based" mechanism would be implemented as part of the FCM. This new mechanism would adjust actual FCM payments received by individual resources such that (1) aggregate FCM revenues would remain unchanged (i.e., revenue-neutral once the FCA has cleared), and (2) each unit's payments would adjust upward or downward depending on its how its *availability* compares to a resource- or unit-specific benchmark.

The "EFOR-based" mechanism includes several components.[58] First, performance would be based on availability metrics reflecting performance during high demand periods, which could reflect a predetermined number of peak load hours (e.g., the top 100 highest load hours) or reserve shortages. These alternatives would have different implications for when performance is measured. Reserve shortages can occur during periods of peak load, but they can also occur during other periods, including winter periods or even shoulder seasons (when maintenance may reduce the supply of available resources). Consequently, reserve shortage hours are typically less predictable than peak load hours, which are typically concentrated during summer periods. An EFOR-based mechanism can also differentially weight hourly availability based on each hour's "importance" for reliability.[59] In other respects, the availability measurement would follow the same type of procedures used in calculating the Effective Forced Outage Rate (EFOR).[60] Second, the FCA (and subsequent reconfiguration auctions) would establish the aggregate payments from load to resources.

Third, FCM payments to each unit would be adjusted based on each unit's availability relative to a pre-determined benchmark. In principle, the benchmark could be based on unit-specific or class-

[56] Note that the NRG Alternative did not specify the value of RCPF assumed, but rather tied the value to the proposed PPR under FCM PI. The current RCPF for ten minute non-spinning reserve (TMNSR) is $850 per MWh, which would rise to $6,305 per MWh with the proposed increase. Other RCPFs would also rise: the system thirty minute operating reserve (TMOR) RCPF would rise to $5,955 per MWh and the local TMOR would be $5,655 per MWh.

[57] If PER Adjustments remain in place with the proposed increase in RCPF values, the financial outcome would be similar to FCM PI. Both the PER Adjustments and PI balancing ratio adjustments operate similar to a financial option, in which resources must pay load whenever certain conditions occur. While the specifics of these options differ somewhat, they are similar enough that an NRG Alternative with PER Adjustments would have many similarities to FCM PI.

[58] *See* Fuller, Pete, NRG, "Market Reform Proposal," NEPOOL Markets Committee, August 7, 2013, slides 5-10.

[59] For example, "UCAP" rules used in ISO-NE's earlier capacity markets adjusted capacity based on an EFOR-based mechanism that weighted availability differentially across hours of the year.

[60] North American Electric Reliability Corporation (NERC), "GADS Data Reporting Instructions," Appendix F – Performance Indexes and Equations, January 2012.

specific historical availability. The assessment presented below assumes a unit-specific benchmark. The change in FCM payment to each resource would be based on the following formula:

$$\Delta FCM\ Payment = MW\ Deviation * FCM\ Price * Marginal\ Multiplier$$

The *FCM Price* would equal the clearing price from the appropriate auction, and the *Marginal Multiplier* is a fixed multiplier that shifts revenue adjustments upwards or downwards. Each unit's *MW Deviation* would reflect differences between its actual and baseline share of available system capacity, which would reflect its availability (relative to its unit-specific benchmark) as well as the availability of all other units in the system (relative to their respective benchmark availability). NRG materials provide further details.[61]

This analysis considers two aspects of the NRG Alternative:

1. $5,455 RCPF Increase + Elimination of PER
2. EFOR-based mechanism

These two elements of the NRG Alternative are evaluated separately to simplify the assessment. The analysis of the NRG Alternative is performed within the same model used to evaluate FCM PI. First, net energy market revenues are adjusted for the elevated prices during reserve shortages and the level of reserve shortages. When comparing the NRG Alternative to FCM PI, we assume the same level of reserve shortage hours; this assumption arises from the conclusion (discussed further below) that the two models provide comparable levels of reliability (assuming that the PPR and RCPF increases are set at the same level). Thus, we assume that there are no resources with energy market offers above the current RCPF values that could mitigate the reserve shortage. Next, FCM revenues are adjusted downward to reflect reduced FCA offers given the reduction in GFC from the additional energy market revenues.

B. Analysis of the NRG Alternative: $5,455 RCPF Increase + Elimination of PER Adjustment

Under both FCM PI and the NRG Alternative, actions to improve resource performance are induced through incremental revenues to resources that supply during reserve shortages. Thus, because both FCM PI and a $5,455 increase in the RCPF will have similar market outcomes and marginal incentives, the anticipated reliability benefits between these proposals should be quite similar. Thus, for the most part, the reliability impacts identified in Section VI.A would be expected under the NRG Alternative, as well as FCM PI.

Table 11 and Figure 14 provide a comparison of FCM clearing prices, energy market payments and total payments by load between FCM PI and the NRG Alternative for the Equilibrium: No Gas scenario. Under the NRG Alternative, FCA offers are reduced to reflect the increase in energy market revenues, which reduces each unit's going forward cost. As a result of these lower offers, the FCM clearing price will be lower than clearing prices under current rules or FCM PI. In fact, in the Equilibrium: No Gas scenario, under the NRG Alternative, the FCA clears at a price of zero. This means that there are sufficient economic resources that do not need FCM revenues to maintain profitable

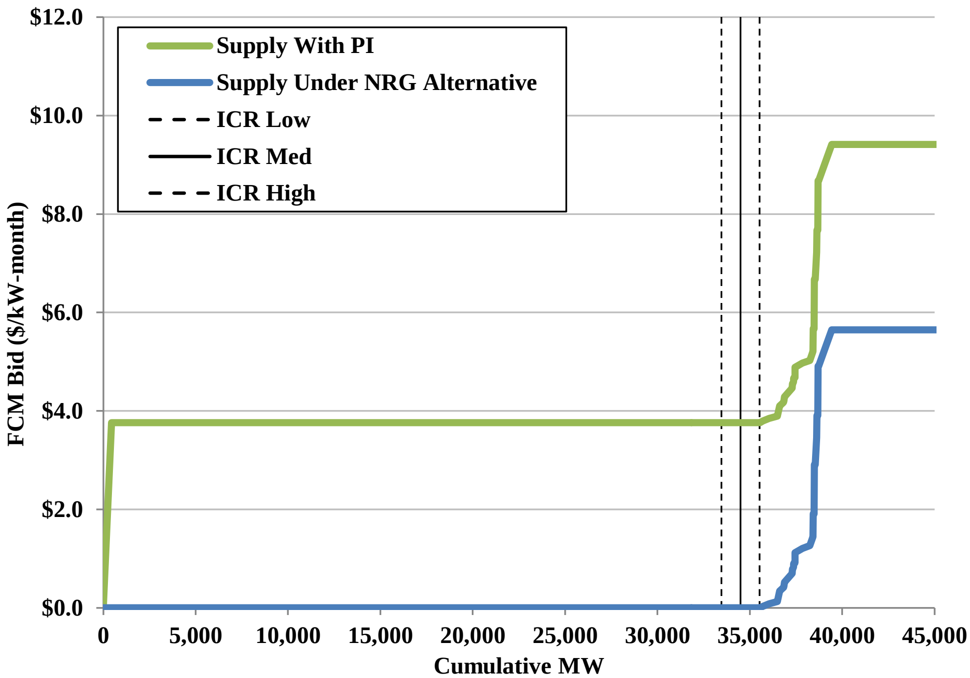
[61] *See* Fuller, Pete, NRG, "Market Reform Proposal," NEPOOL Markets Committee, August 7, 2013, slides 7-8.

operation (i.e., resources with negative going forward costs) to meet the ICR. In practice, if this occurs, market outcomes could reflect bidding behavior in which market participants submit FCA offers that exceed the resource GFC, resulting in a clearing price that is greater than zero.[62] We do not model bidder behavior under these circumstances. To the extent that the FCA cleared with positive prices under this scenario, payments under the NRG Alternative would exceed those under FCM PI by the FCM payments corresponding to this positive FCA price.

Table 11: Market Outcomes with FCM PI and NRG Alternative, Equilibrium: No Gas Scenario

	With FCM PI	With NRG Alternative	Difference
FCA Clearing Price	$3.76	$0.00	($3.76)
FCM Payments ($ billion)	$1.56	$0.00	($1.56)
Additional RCPF Payments ($ billion)	$0.00	$1.56	$1.56
Total Payments to Suppliers ($ billion)	**$1.56**	**$1.56**	**$0.00**

Figure 14: FCM Offer Curve, FCM PI versus NRG Alternative

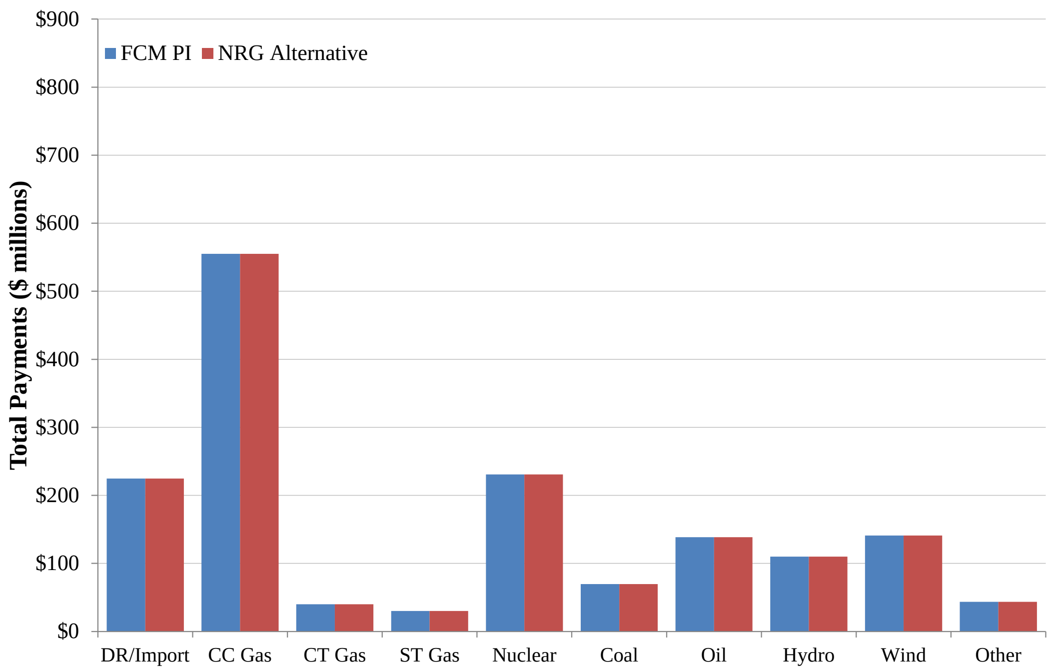


[62] Offers could reflect strategic bidding behavior in an effort to achieve a positive FCA price, or opportunity costs of taking on a CSO (e.g., administrative costs or compliance risk).

Table 11 shows the total FCM payments and the changes in energy market payments, as reflected in increased RCPF values, under FCM PI and NRG Alternative. Under the Equilibrium: No Gas scenario, expected payments are the same under the two alternatives. The NRG Alternative results in additional energy (RCPF) market payments of $1.56 billion, but FCM payments equal zero. By contrast, FCM PI results in FCM payments of $1.56 billion but no change in energy market payments. Thus, both alternatives have the same impact on payments in the FCM and energy markets.

While expected payments are the same under FCM PI and the NRG Alternative, actual payments can differ depending on the actual level of reserve shortages. Consider the three possible outcomes in Figures 15, 16 and 17, which show the payments made under each approach to different resource types for different levels of actual reserve shortages. Figure 15 shows that payments under the two alternatives are the same when the actual and expected levels of reserve shortages are the same. However, Figures 16 and 17 show that when the actual and expected levels of reserve shortages differ, payments under the two models will diverge.[63] These figures illustrate two important differences between the programs.

Figure 15: Total Payments Under FCM PI and NRG Alternative by Fuel Type, Actual Reserve Shortages Equals Expected Reserve Shortages



First, there is less variation in payments under FCM PI than the NRG Alternative. For each resource category, the change in payments when actual reserves shortage levels differ from expectations is greater under the NRG Alternative than FCM PI. Thus, in aggregate, the NRG Alternative results in greater volatility in payments by load and to suppliers. This greater volatility translates into a higher level of aggregate financial risk for both customers (load) and resources, although, as discussed below, the implications for individual resources vary depending on resource-specific characteristics.

[63] These scenarios assume 9, 5, and 15 reserve shortage hours for Figures 15, 16 and 17, respectively.

Figure 16: Total Payments Under FCM PI and NRG Alternative by Fuel Type, Actual Reserve Shortages Less Than Expected Reserve Shortages

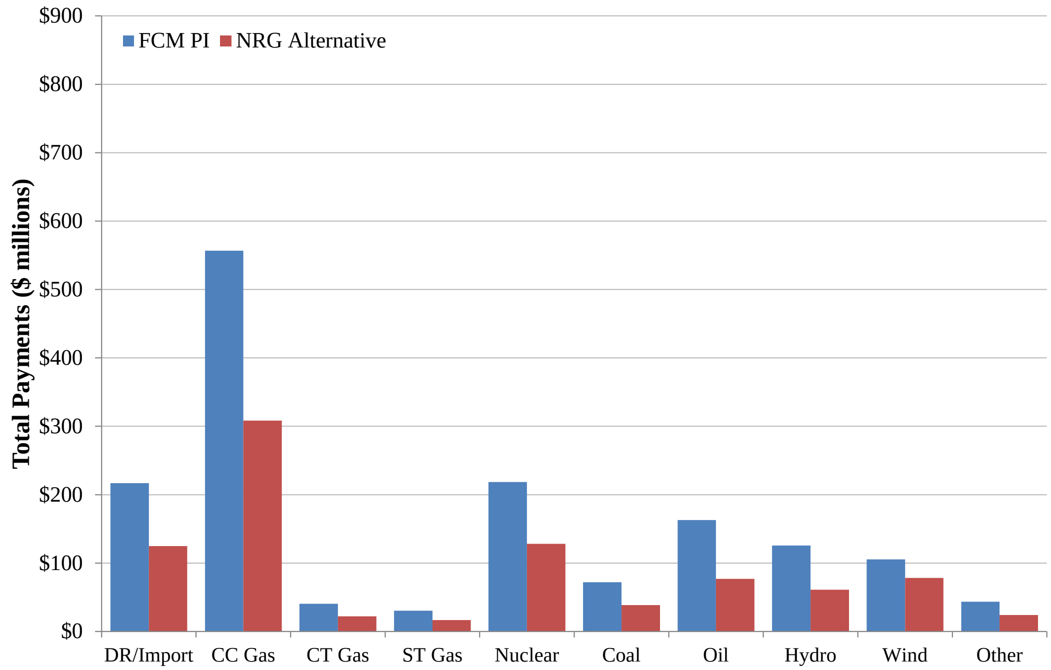
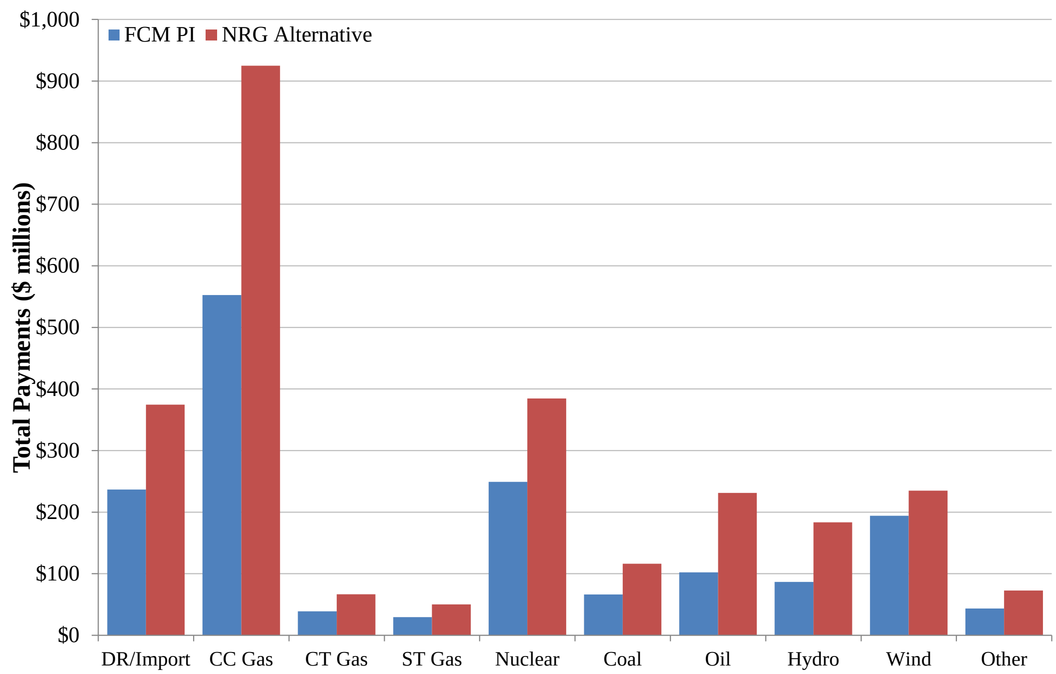


Figure 17: Total Payments Under FCM PI and NRG Alternative by Fuel Type, Actual Reserve Shortages Greater Than Expected Reserve Shortages



Second, under the NRG Alternative, all resources receive higher payments as the level of reserve shortages increases. By contrast, payments under FCM PI can increase or decrease with a higher level of reserve shortages depending on whether the resource is a high or low performer. For example, payments to nuclear resources, with performance levels typically above the balancing ratio, increase from $218 million to $249 million as reserve shortage levels increase (from Low to High). By contrast payments to oil resources decline from $163 to $102 as reserve shortage levels increase (from Low to High).

Figures 15 to 17 unmask some important differences in payment volatility between the two alternatives that are relevant for individual resources. Figure 18 shows the payments made under FCM PI and the NRG Alternative to illustrative units under varying levels of reserve shortages. The figures (calculated for Historical conditions) show that for individual resources, the implications of uncertainty in reserve shortages vary significantly depending on the resource's performance. For high performing units (90-100%), payments vary little under FCM PI, whereas they vary by nearly a factor of three under the NRG Alternative. For average performing units (60-70% performance), variation is still less under FCM PI than the NRG Alternative, although the degree of variation is of the same order of magnitude. However, for low performing resources (10-20%), variation is greater under FCM PI, and the resource faces the risk of negative net FCM payments. Thus, while FCM PI results in less financial risk for high performing resources, financial risk is greater for low performing resources relative to the NRG Alternative.

C. Analysis of the NRG Alternative: EFOR-based mechanism

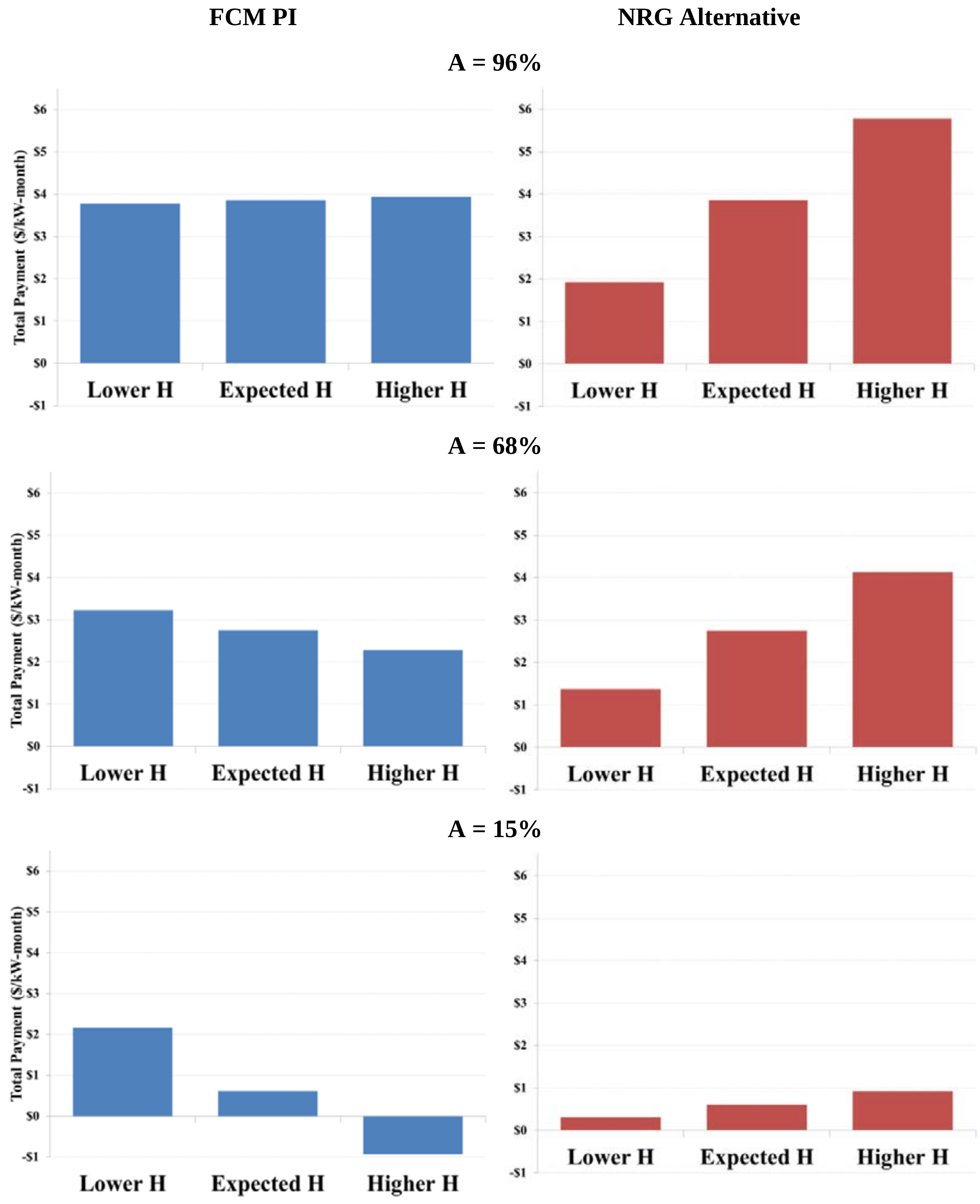
The introduction of the EFOR-based mechanism (in addition to the $5,455 RCPF increase and the elimination of the PER Adjustments) could have implications for both reliability and market outcomes. From a reliability standpoint, the introduction of EFOR-based incentives for availability in addition to the increase in RCPFs of $5,455 per MWh would further enhance the incentives to improve performance. The incremental incentives would be limited to actions that improved *availability*, but would not affect other sorts of operational performance. Our analysis does not consider any quantitative benefits that would arise from these additional incentives.

In terms of potential market outcomes, impacts would depend strongly on assumptions about expected future performance. The EFOR-based mechanism could affect resource offers depending on the expectations of each market participant regarding future resource availability compared to the benchmark against which each resource's availability is measured.

Under the NRG Alternative, benchmarks would be set at the individual resource level based on historical availability. Under this rule, the most reasonable assumption about a market participant's expectation about future availability is that it will reflect past historical availability. However, if resource benchmarks are also based on historical availability, then market participants' expectations about future availability would equal the benchmark availability. Consequently, market participants would not expect to win or lose as a consequence of the rule, and would not adjust their FCM offers, leaving FCA prices unchanged.

If benchmarks were set based on broader resource categories, then resources would find it optimal to adjust their offers upward or downward depending on whether their past availability was higher or lower than their category average. We have not quantitatively evaluated such a proposal.

Figure 18: Payments to Illustrative Individual Units Under FCM PI and the NRG Alternative



VIII. CONCLUSIONS

The assessment of ISO-NE's FCM PI proposal has identified a range of changes to reliability, costs and payments by load. The assessment identifies many types of potential impacts and analyzes these through quantitative estimates and qualitative assessments.

These results indicate that FCM PI would likely result in improvements to reliability through several mechanisms, including: increases in the quantity of resources participating in the ISO-NE markets; investments to improve resource performance, including investments to develop dual fuel capability at gas-dependent resources; and changes to the mix of resources that remain in the ISO-NE fleet and are used to satisfy the region's Installed Capacity Requirement. Reliability benefits would likely be greatest in summer peak load periods (from surplus capacity) and in winter months, particularly during periods of high gas demand (from surplus capacity and dual fuel investments).

FCM PI would result in a variety of cost impacts, including changes to production costs, new investments to improve performance, and potential delays in the timing of when new generation resources are required to meet the ICR. Our analysis does not quantitatively estimate the net impact of these various effects.

The results indicate that FCM PI would likely raise FCA prices under most circumstances when prices clear below the cost of new entry (under current market rules). However, FCM PI would likely lower offers from new entry due to the incremental revenues provided under FCM PI, particularly as these resources are likely to (and under FCM PI have incentives to) be high performing resources. Consequently, in the long-run, FCM PI could lower FCA prices as the market nears an equilibrium in which new generation resources are required. Increases in FCM payments under the equilibrium scenarios would reflect a 5% to 10% increase in 2012 wholesale energy payments.

The key element of the NRG Alternative – the $5,455 increase in RCPF values – would provide comparable reliability benefits and expected costs, but have different implications for the financial risk born by suppliers and load given the variation in aggregate payments under the NRG Alternative compared to FCM PI. FCM PI would reduce variation in total FCM payments, which would be not exceed the prices established in the FCA. Under the NRG Alternative, FCM payments would vary depending on system conditions (the level of reserve shortages, and loads during these shortages) during the commitment period.

APPENDIX A: METHODOLOGICAL APPROACH AND DATA ASSUMPTIONS

A. Going-Forward Costs

Going-forward costs are calculated using the following formula:

$$Offer(FCM) = \frac{GFC + RF}{Capacity * 12} = \frac{FC + I - Q*\left(P - VC - HR * P_{Fuel}\right) + RF}{Capacity * 12}$$

Fixed costs (*FC*) and investments (*I*) are offset by the remainder of the equation, reflecting net energy and ancillary services market revenues, where *Q* is the quantity of output sold, *P* is the average energy market price, *VC* is the non-fuel variable costs, *HR* is the unit's heat rate, and P_{Fuel} is the fuel price. *RF* is the risk factor. *Capacity* reflects the resources Summer Qualified Capacity, the quantity (in MW) of each resource's nameplate capacity that is eligible to bid into the FCA (for the summer months). The individual elements of the above formula are calculated using the following data and assumptions.

Fixed Costs

Fixed O&M costs for each unit are reported in SNL Financial for 2011. These values are adjusted to reflect a $/kW-year cost and applied to each unit's Summer Qualified Capacity as reported in FCA 7. Values for units that do not have reported data in SNL are imputed based on category averages for similar units based on unit size, vintage, and fuel type. For imputed fixed costs, an additional random noise factor of 0-1% is added, to avoid a situation where multiple units have the same GFC. Costs for certain resources were adjusted in light of resource- or region-specific information about costs from a variety of sources.

Investment Costs

Investment costs are broken into two components: costs to install and operate dual-fuel fired capability and costs to install and operate equipment for environmental compliance. Other investments needed for resources to continue operations are not considered. Appendix C provides detail on the methodology, data, and assumptions used for dual-fuel investment decisions.

The need for environmental compliance equipment installation is based on Analysis Group's review of prior ISO-NE analyses of which generators may face CWA Section §316(b) regulations. The analysis assumes that 50% of the overall capacity potentially at risk actually faces additional Section §316(b) requirements, including all coal units, the two oldest nuclear plants, and the oldest oil units. In total, 19 generators are assumed to face additional environmental investments to continue operation.

Fossil fuel units facing compliance costs are assessed a 1.3% penalty to heat rate and a 3.4% penalty to MW capacity. For nuclear generators, there is a 1.5% penalty to heat rate and 1.0% penalty to MW capacity. Depreciation of investment costs is based on the useful life remaining of the asset, using

ISO-NE Market Rule guidance and the Offer Review Trigger Price (ORTP) study performed by Shaw Consultants International, Inc.[64] In addition, a depreciation tax shield is assumed on investment costs, of:

$$Corporate\ Tax\ Rate * \left(\frac{Upfront\ Costs}{5\ years}\right).$$

A discount rate of 5.67% is used for calculating investment costs, representing the Weighted Average Cost of Capital (WACC) methodology provided in Shaw Consultants' ORTP study, updated to reflect current market rates.

Variable Costs

Variable O&M costs for each unit are reported in SNL Financial for 2011. These values are adjusted to reflect a $/MWh cost and applied to each unit's average of 2010-2012 actual net generation as reported by ISO-NE. Values for units that do not have reported data in SNL are imputed based on category averages for similar units based on unit size, vintage, and fuel type.

Fuel expenditures are calculated using unit heat rates and fuel costs. Unit heat rates are based on SNL Financial data for 2011. Values for units that do not have reported data in SNL are imputed based on category averages for similar units based on unit size, vintage, and fuel type.

Natural gas prices are based on NYMEX Henry Hub natural gas futures for 2018-2019, and are then adjusted to account for a basis differential reflecting the difference in prices between Henry Hub and New England hub prices over the last three years. Oil and coal price forecasts are delivered fuel prices to electricity generators in the New England region from EIA's 2013 Annual Energy Outlook. Nuclear fuel prices reflect the reported unit prices from SNL for 2011, with no anticipated change.

Revenues

LMPs are estimated based on a regression of unit-level average annual LMPs on year-end natural gas prices. This specification is consistent with the assumption that gas-fired resources are the marginal units during most hours in recent years. A separate regression is run for each technology/fuel type, with unit-level fixed effects. The results of these regressions are used to forecast expected average prices for each unit for the 2018/2019 commitment year. Average LMP estimates are calculated using the technology/fuel-specific parameters for gas prices, forecast gas prices, and each unit's individual fixed effect. Through this approach, both fuel-level and unit-level heterogeneity are captured in the LMP model. ISO-NE LMP data from 2007-2012 are used in the regression model.

Ancillary service payments are collected from ISO-NE data for NCPC payments, regulation payments, and real-time reserve payments. The 2018-2019 ancillary payments per MWh for each unit are assumed to be the average of actual payments per MWh over 2010-2012.

[64] While new ORTP values developed by Brattle Group and Sargent & Lundy are used, the financial assumptions used in assessing capital investments based on the prior Shaw ORTP study.

Non-Reported Revenues

All cogeneration plants, and plants running on biomass, hydro, solar, fuel cells, or wind are assumed to have a GFC equal to zero. This is based on the expectation that these plants will have significant non-energy-market revenues or credits that are not captured in the data sources used.

Other Inputs

The inflation index used was the Federal Reserve Board's prediction of long-run PCE inflation, 2.0%.[65] Details on the risk factor methodology and calculation can be found in the main text of the report in Section V.F.

Going-Forward Costs for New Entry

New unit going-forward cost estimates are taken from the study of Offer Review Trigger Prices (ORTP) performed by the Brattle Group and Sargent & Lundy.[66] The model only considers new entry for combined cycle and combustion turbine resources, although the study evaluates other resource types.

B. Operational Performance

Data used to estimate operational performance *A* and balancing ratio *BR* is as follows:

1. Average Historical Conditions: Estimates reflect performance during all system reserve shortages that occurred during the period 2010 to 2012.[67]
2. Peak (Summer) Conditions: Estimates reflect performance during all system reserve shortages that occurred during the months of June, July and August during the period 2010 to 2012.
3. Winter Peak Conditions: Estimates reflect performance during all hours when the balancing ratio exceeded 0.6 during winter months in the years 2010 to 2012.[68]

[65] Federal Reserve Board, "Economic Projections of Federal Reserve Board Members and Federal Reserve Board Presidents, March 2013," March 20, 2013. Available at: http://www.federalreserve.gov/monetarypolicy/files /fomcprojtabl20130320.pdf.
[66] Brattle Group, "ISO-NE Offer Review Trigger Prices 2013 Study, Final Results," presented to the NEPOOL Markets Committee, September 10, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps /mrkts_comm/mrkts/mtrls/2013/sep10112013/a02_the_brattle_group_presentation_09_10_13.ppt.
[67] System reserve shortages considered include shortages under the current RCPFs of $500 per MWh for TMOR. These include actual reserve shortages from June to December 2012, when $500 TMR RCPFs were in effect, and reserve shortages identified in simulations performed by ISO-NE for the period January 2010 through May 2012. These data are reported in ISO-NE, "Reserve Constraint Penalty Factor Activation Data, October 2006 - December 2012," March 5, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls /2013/mar11122013/a14_iso_rcpf_activation_data_03_05_13.xlsx.
[68] Across units, performance during system reserve shortages in winter months was highly variable. Consequently, performance during high load periods, as reflected by the balancing ratio, was used in lieu of performance during reserve shortages.

Performance is measured as the ratio of total output and operating reserves (*MW*) supplied over all of the reserve shortages (*RS*) (during the relevant time period) divided by the product of the total qualified capacity (*SCC*) and the duration of the reserve shortages (*H*) – that is:

$$A = \frac{\sum_{RS} MW}{SCC * H}$$

Performance is measured over the resource's entire eligible capacity.

The balancing ratio equals load plus reserves divided by ICR. The average balancing ratio equals the sum of the loads during all reserve shortages divided by the product of the ICR times the number of reserve shortages hours – that is:

$$BR = \frac{\sum_{RS} L}{ICR * H}$$

C. Demand Response, Imports, and Renewables

Demand response (DR) is assumed to bid into the FCM PI model in the same amounts as FCA 7. Two categories of DR exist in the model:

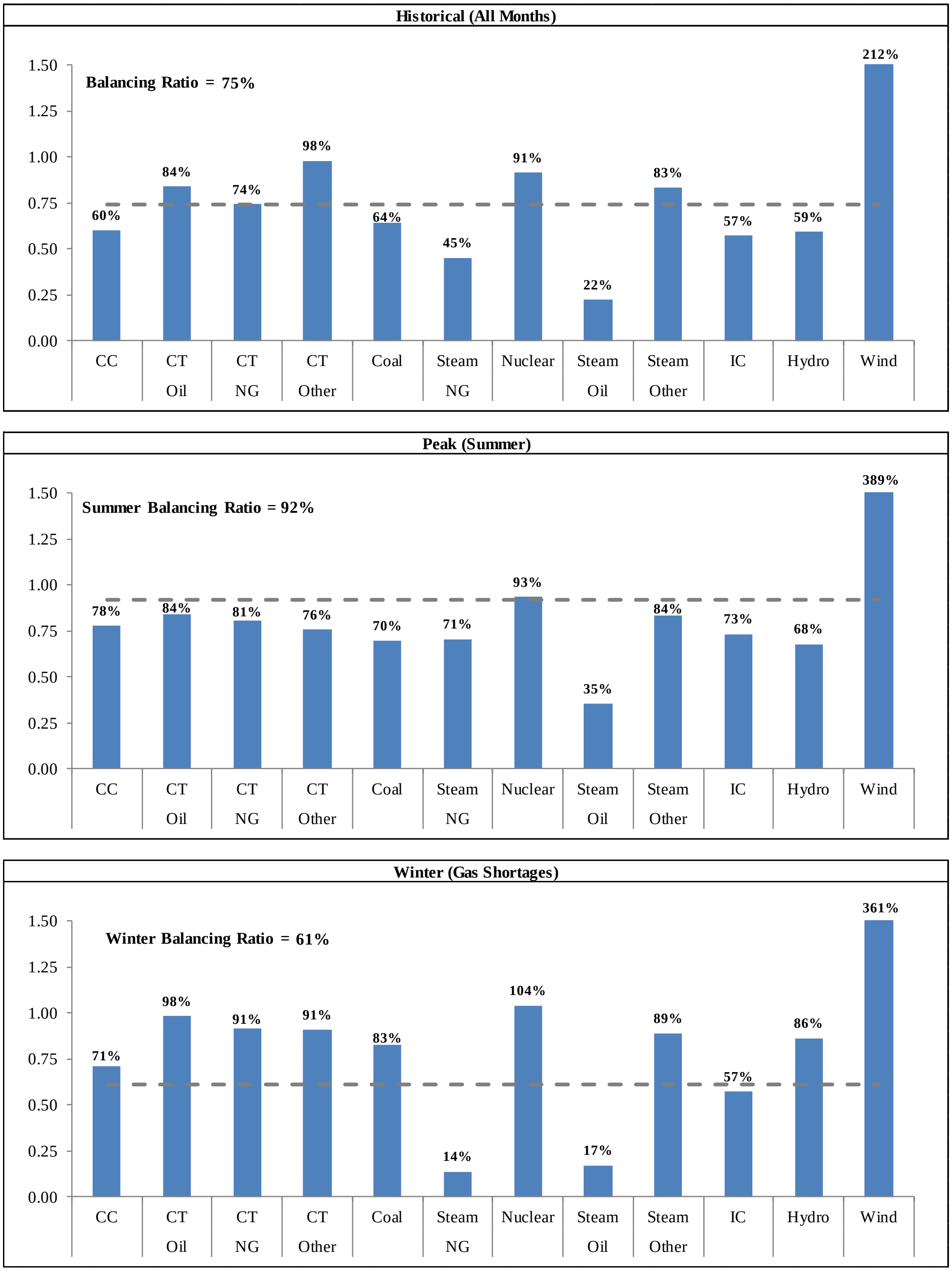
1. Passive DR: 1,850 MW of supply is assumed to be fixed given existing utility-operated energy efficiency programs. These resources are "price takers" in the model – that is, they will accept any price.
2. Active DR: Lacking detailed information on the supply of DR at various prices, the aggregate supply of DR is assumed to grow linearly between several known price/quantity pairs from FCA 7 (i.e., the quantity supplied at each price in the descending clock auction). Starting at bids of $14.00, 856 MW of DR delists linearly in 50 cent increments down to $0.50. The remaining 917 MW of DR is assumed fixed (i.e., resources are price takers down to a very low price).

Imports are treated similarly to active DR in the FCM PI model. The 1,830 MW of imports with capacity supply obligations in FCA 7 are assumed to linearly delist in 450 MW and $1.00 increments starting at $4.00, with the last 30 MW bidding in at $0.10.

Sufficient renewables are added to the fleet to meet state RPS standards in 2018-2019. Based on the most recent ISO New England Regional System Plan[69], 1,142 MW of onshore wind is added beyond what has already cleared in FCA 7 to achieve these requirements. This capacity total reflects the quantity of renewables eligible for the FCM, using a 31% capacity factor.

[69] ISO New England, "Regional System Plan", November 2, 2012.

Figure A1: Average Unit Performance by Resource Category



[1] "Unit Performance" is calculated for each unit and event as a unit's average output during the event divided by its summer seasonal claimed capability (summer SCC). The summer SCC used is from the most recent year with available data. Mean unit performance is weighted by summer SCC.
[2] Summer SCC, generation type, and primary fuel type from CELT Reports. Operating data from ISO-NE.

Table A1
Unit and Class Performance During System Reserve Shortage Events
Summary Statistics by Generation/Primary Fuel Type
All Months January 2010 - December 2012

	Unit Performance				
Generation/Primary Fuel Type	**Mean**	**Standard Deviation**	**Minimum**	**Maximum**	**Aggregate Class Performance**
Combined Cycle	0.60	1.20	0.00	12.40	0.67
Gas Turbine/Oil	0.84	0.46	0.00	1.92	0.93
Gas Turbine/Natural Gas	0.74	0.45	0.00	1.30	0.84
Gas Turbine/Other	0.98	0.37	0.00	1.55	0.94
Steam/Coal	0.64	0.43	0.00	1.07	0.89
Steam/Natural Gas	0.45	0.37	0.00	1.06	0.60
Steam/Nuclear	0.91	0.26	0.00	1.18	1.02
Steam/Oil	0.22	0.40	0.00	1.25	0.28
Steam/Other	0.83	0.40	0.00	2.73	0.99
Internal Combustion Engine	0.57	0.52	0.00	2.58	0.64
Hydro	0.59	2.19	0.00	30.65	0.78
Wind Turbine	2.12	2.60	0.00	10.02	3.28

Notes:

[1] "Unit Performance" is calculated for each unit and event as a unit's average output during the event divided by its summer seasonal claimed capability (summer SCC). The summer SCC used is from the most recent year with available data. Mean unit performance is weighted by summer SCC.

[2] "Aggregate Class Performance" is calculated as total class output divided by total class summer SCC.

[3] Summer SCC, generation type, and primary fuel type from CELT Reports. For each unit, data comes from the most recent year with available data.

[4] The system RCPF value equaled $100 until June 1, 2012, at which point it was increased to $500. ISO-NE used a simulation to determine when reserve events would have occurred with a system RCPF value of $500 for the period from January 2010 - May 2012. The data from this simulation was used together with data on actual reserve events for the period from June 2012 - December 2012 to calculate unit performance and aggregate class performance for the period from January 2010 - December 2012.

Table A2
Unit and Class Performance During System Reserve Shortage Events
Summary Statistics by Generation/Primary Fuel Type
Summer Months January 2010 - December 2012

	Unit Performance				
Generation/Primary Fuel Type	**Mean**	**Standard Deviation**	**Minimum**	**Maximum**	**Aggregate Class Performance**
Combined Cycle	0.78	1.05	0.00	10.61	0.86
Gas Turbine/Oil	0.84	0.38	0.00	1.92	0.93
Gas Turbine/Natural Gas	0.81	0.34	0.00	1.16	0.92
Gas Turbine/Other	0.76	0.33	0.00	1.22	0.72
Steam/Coal	0.70	0.35	0.00	1.07	0.99
Steam/Natural Gas	0.71	0.25	0.00	1.06	0.91
Steam/Nuclear	0.93	0.14	0.66	1.18	1.04
Steam/Oil	0.35	0.44	0.00	1.25	0.43
Steam/Other	0.84	0.36	0.00	2.36	1.03
Internal Combustion Engine	0.73	0.42	0.00	1.65	0.77
Hydro	0.68	1.48	0.00	16.77	0.90
Wind Turbine	3.89	2.30	0.00	10.02	4.60

Notes:
[1] "Unit Performance" is calculated for each unit and event as a unit's average output during the event divided by its summer seasonal claimed capability (summer SCC). The summer SCC used is from the most recent year with available data. Mean unit performance is weighted by summer SCC.
[2] "Aggregate Class Performance" is calculated as total class output divided by total class summer SCC.
[3] Summer SCC, generation type, and primary fuel type from CELT Reports. For each unit, data comes from the most recent year with available data.
[4] The system RCPF value equaled $100 until June 1, 2012, at which point it was increased to $500. ISO-NE used a simulation to determine when reserve events would have occurred with a system RCPF value of $500 for the period from January 2010 - May 2012. The data from this simulation was used together with data on actual reserve events for the period from June 2012 - December 2012 to calculate unit performance and aggregate class performance for the period from January 2010 - December 2012. Data are limited to reserve events during June, July, and August.

Table A3
Unit and Class Performance During System Reserve Shortage Events
Summary Statistics by Generation/Primary Fuel Type
Winter Months January 2010 - December 2012

	Unit Performance				
Generation/Primary Fuel Type	**Mean**	**Standard Deviation**	**Minimum**	**Maximum**	**Aggregate Class Performance**
Combined Cycle	0.71	1.51	0.00	11.90	0.72
Gas Turbine/Oil	0.98	0.45	0.00	1.71	1.00
Gas Turbine/Natural Gas	0.91	0.51	0.00	1.37	0.89
Gas Turbine/Other	0.91	0.51	0.00	1.45	0.90
Steam/Coal	0.83	0.29	0.00	1.07	0.97
Steam/Natural Gas	0.14	0.37	0.00	1.08	0.16
Steam/Nuclear	1.04	0.10	0.45	1.18	1.04
Steam/Oil	0.17	0.37	0.00	1.11	0.20
Steam/Other	0.89	0.41	0.00	2.50	0.98
Internal Combustion Engine	0.57	0.51	-0.14	2.19	0.57
Hydro	0.86	1.96	0.00	14.45	0.88
Wind Turbine	3.42	3.32	0.00	10.83	3.73

Notes:
[1] "Unit Performance" is calculated for each unit and event as a unit's average output during the event divided by its summer seasonal claimed capability (summer SCC). The summer SCC used is from the most recent year with available data. Mean unit performance is weighted by summer SCC.
[2] "Aggregate Class Performance" is calculated as total class output divided by total class summer SCC.
[3] Summer SCC, generation type, and primary fuel type from CELT Reports. For each unit, data comes from the most recent year with available data.
[4] The system RCPF value equaled $100 until June 1, 2012, at which point it was increased to $500. ISO-NE used a simulation to determine when reserve events would have occurred with a system RCPF value of $500 for the period from January 2010 - May 2012. The data from this simulation was used together with data on actual reserve events for the period from June 2012 - December 2012 to calculate unit performance and aggregate class performance for the period from January 2010 - December 2012. Data are limited to periods events during December, January, and February when the balancing ratio exceeded 0.6.

APPENDIX B: DETAILED SCENARIO RESULTS

Table B1: Resource Mix and Average Performance With and Without FCM PI, Historical: No Gas Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,769	100%	1,739	100%
Renewables	4,705	83%	0	NA
Nuclear	4,628	102%	0	NA
CC Gas	12,470	72%	315	48%
Coal	1,591	73%	543	85%
CT or ST Gas	1,520	72%	122	65%
Oil	4,862	44%	1,786	11%
Other	1,071	87%	0	NA
Total	34,615		4,506	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	83%	0	NA
Nuclear	4,628	102%	0	NA
CC Gas	12,470	72%	315	48%
Coal	1,591	73%	543	85%
CT or ST Gas	1,520	72%	122	65%
Oil	5,601	39%	1,047	27%
Other	1,071	87%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	459	0.0%	-459	0.0%
Renewables	0	0.0%	0	NA
Nuclear	0	0.0%	0	NA
CC Gas	0	0.0%	0	0.0%
Coal	0	0.0%	0	0.0%
CT or ST Gas	0	0.0%	0	0.0%
Oil	-739	5%	739	-16%
Other	0	0.0%	0	NA

Notes:
[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.
[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).
[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine
ST: Steam Turbine.

Table B2: Resource Mix and Average Performance With and Without FCM PI, Historical: Gas Shortage Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,258	100%	1,250	100%
Renewables	4,705	91%	0	NA
Nuclear	4,628	104%	0	NA
CC Gas	12,470	72%	315	47%
Coal	1,703	75%	431	86%
CT or ST Gas	1,499	61%	143	48%
Oil	4,171	40%	2,478	13%
Other	1,070	88%	0	15%
Total	34,504		4,617	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	91%	0	NA
Nuclear	4,628	104%	0	NA
CC Gas	12,470	72%	315	47%
Coal	1,591	74%	543	89%
CT or ST Gas	1,520	60%	122	52%
Oil	5,601	34%	1,047	21%
Other	1,071	88%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	948	0.0%	-948	0.0%
Renewables	0	0.0%	0	NA
Nuclear	0	0.0%	0	NA
CC Gas	0	0.0%	0	0.0%
Coal	113	2%	-113	-3%
CT or ST Gas	-21	0.5%	21	-4%
Oil	-1,430	6%	1,430	-8%
Other	0	0.0%	0	NA

Notes:
[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.
[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).
[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine
ST: Steam Turbine.

Table B3: Resource Mix and Average Performance With and Without FCM PI, Historical: High Gas Shortage Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,717	100%	791	100%
Renewables	4,705	93%	0	NA
Nuclear	4,628	104%	0	NA
CC Gas	12,442	74%	343	50%
Coal	2,039	78%	95	82%
CT or ST Gas	1,499	61%	143	43%
Oil	3,416	41%	3,232	15%
Other	1,070	88%	0	15%
Total	34,516		4,605	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	93%	0	NA
Nuclear	4,628	104%	0	NA
CC Gas	12,470	74%	315	52%
Coal	1,591	74%	543	90%
CT or ST Gas	1,520	61%	122	48%
Oil	5,601	32%	1,047	19%
Other	1,071	88%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,407	0.0%	-1,407	0.0%
Renewables	0	0.0%	0	NA
Nuclear	0	0.0%	0	NA
CC Gas	-28	0.1%	28	-3%
Coal	448	4%	-448	-8%
CT or ST Gas	-21	0.6%	21	-5%
Oil	-2,185	9%	2,185	-4%
Other	0	0.0%	0	NA

Notes:
[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.
[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).
[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine
ST: Steam Turbine.

Table B4: Resource Mix and Average Performance With and Without FCM PI, Equilibrium: No Gas Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,717	100%	791	100%
Renewables	4,698	112%	7	4%
Nuclear	4,628	105%	0	NA
CC Gas	12,712	91%	74	22%
Coal	1,703	86%	431	90%
CT or ST Gas	1,642	89%	0	NA
Oil	4,366	66%	2,282	14%
Other	1,070	91%	0	15%
Total	35,536		3,585	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	112%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,470	92%	315	70%
Coal	1,591	85%	543	93%
CT or ST Gas	1,520	89%	122	91%
Oil	5,601	54%	1,047	39%
Other	1,071	91%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,407	0.0%	-1,407	0.0%
Renewables	-7	0.2%	7	NA
Nuclear	0	0.0%	0	NA
CC Gas	241	-0.1%	-241	-48%
Coal	113	1.3%	-113	-3%
CT or ST Gas	122	0.1%	-122	NA
Oil	-1,235	12%	1,235	-25%
Other	0	0.0%	0	NA

Notes:

[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.

[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).

[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

Table B5: Resource Mix and Average Performance With and Without FCM PI, Equilibrium: Gas Shortage Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,917	100%	591	100%
Renewables	4,698	108%	7	27%
Nuclear	4,628	105%	0	NA
CC Gas	12,712	85%	74	36%
Coal	2,039	84%	95	87%
CT or ST Gas	1,642	77%	0	NA
Oil	4,185	58%	2,463	13%
Other	1,070	90%	0	15%
Total	35,890		3,231	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	108%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,470	85%	315	63%
Coal	1,591	81%	543	93%
CT or ST Gas	1,520	77%	122	75%
Oil	5,601	46%	1,047	32%
Other	1,071	90%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,607	0.0%	-1,607	0.0%
Renewables	-7	0.1%	7	NA
Nuclear	0	0.0%	0	NA
CC Gas	241	-0.3%	-241	-27%
Coal	448	3%	-448	-6%
CT or ST Gas	122	-0.1%	-122	NA
Oil	-1,416	12%	1,416	-18%
Other	0	0.0%	0	NA

Notes:

[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.

[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).

[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

Table B6: Resource Mix and Average Performance With and Without FCM PI, Equilibrium: High Gas Shortage Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,976	100%	532	100%
Renewables	4,705	106%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,712	84%	74	44%
Coal	2,039	83%	95	88%
CT or ST Gas	1,642	73%	0	NA
Oil	4,201	51%	2,447	13%
Other	1,070	90%	0	15%
Total	35,972		3,149	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	106%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,470	84%	315	63%
Coal	1,591	80%	543	93%
CT or ST Gas	1,520	73%	122	66%
Oil	5,601	42%	1,047	27%
Other	1,071	89%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,666	0.0%	-1,666	0.0%
Renewables	0	0.0%	0	NA
Nuclear	0	0.0%	0	NA
CC Gas	241	-0.3%	-241	-18%
Coal	448	3%	-448	-5%
CT or ST Gas	122	-0.5%	-122	NA
Oil	-1,400	9%	1,400	-14%
Other	0	0.0%	0	NA

Notes:
[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.
[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).
[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine
ST: Steam Turbine.

APPENDIX C: ASSESSMENT OF ALTERNATIVE TECHNICAL OPTIONS FOR SECURING FUEL SUPPLY

This appendix provides qualitative and quantitative background information on categories of potential costs associated with new infrastructure alternatives to address risks of natural gas fuel curtailment, or "gas dependence" risks. This information is used to identify the least-cost approach to addressing gas-dependency risks. This assessment considers the direct cost of these options, but does not consider indirect economic impacts, such as net revenues gained from increased output in the energy market, or changes in fuel costs.

The assessment relies on various studies, reports, and analyses conducted by third parties and available in the public domain, related to natural gas and dual fuel infrastructure options that could emerge from market rule changes, along with estimates developed by Analysis Group based on information and data provided by ISO-NE or contained in these studies and reports. The list of studies reviewed is presented at the end of this memo.

There are a number of potential technical options that resources can take to address gas dependence risks. Our assessment considers the following options:[70]

- Increases in dual-fuel capability or operations
    - From existing units with dual fuel capability that is currently mothballed or underutilized
    - From newly developed dual fuel capability at existing gas plants
- Storage/transportation arrangements tied to existing LNG facilities
- New in-region LNG storage
- New natural gas interstate pipeline capacity

The identification of the least-cost approach to mitigate gas dependence reflects the cost-effectiveness of each option to resource owners. This assessment also considers (1) feasibility and the timeline for development, and (2) operational characteristics to ensure that the resource owners would have sufficient time to implement the technical option for the commitment period, that there are not regulatory, technical or practical barriers to deploying the option, and that the option addresses gas dependence risks with reasonable certainty. In the sections that follow, information and data are presented for each of these factors, and for each of the options identified. Specifically, we review:

1. *Costs* – life-cycle costs, including upfront costs and annual operating costs.[71] Options are compared based on their annualized cost (dollars per kW-month), reflecting assumptions about the discounting of each option's upfront costs. The cost estimates reflect implementation of the option at generic resources based on data provided by ISO-NE and publicly available information

[70] It should be noted that there may be additional or alternative outcomes of market rule changes focused on natural gas dependence that are not identified or evaluated in this memo.

[71] In addition to these infrastructure development and operational costs, the integration of such new infrastructure would likely have an impact (positive or negative) on *system costs* over time. Such impacts could arise, for example, from changes in system unit commitment and dispatch in some or all hours of the year given the integration of new resources, and/or changes in system transmission costs. These system cost impacts are not reviewed in this analysis.

on recent development projects. Unless noted below, the estimates do not reflect resource-specific factors that would lead actual costs to vary from these estimates. Figure C1 describes how categories of costs are identified and normalized to allow for comparison.

2. *Development timeline/feasibility* – the time required between conceptualization and commercialization for the options reviewed varies widely. The analysis presents qualitative assessments of development feasibility and barriers to implementation that would affect when specific alternatives would be available to influence reliability and market outcomes.

3. *Operational characteristics* – not all options reviewed provide equal assurance of fuel delivery or generation availability, and so they present different implications for resource availability that may or may not affect market valuation. For example, options differ in their (1) ability to ensure fuel delivery for prolonged or frequent curtailments, (2) ability to support reserve-quality resources, and (3) ability to withstand interstate natural gas pipeline contingencies. The analysis presents qualitative assessments of operational constraints that would affect how specific alternatives would influence reliability and market outcomes.

Figure C1: Analytic Approach to Estimating Costs of Options to Address Gas Dependence

Capacity (MW)	200
Upfront Cost	
Project cost ($)	1,000,000
Total Upfront Costs ($)	1,000,000
Annual Costs	
O&M ($)	1,500,000
Carrying Cost ($)	1,000,000
Total Annual Costs ($)	2,500,000
PV	
Lifetime	20
Discount Rate	9%
Present Value ($)	23,821,364
Present Value per MW ($)	119,107
Cost per kW-month ($)	1.09

Each facility is sized to serve a quantity of gas-fired capacity

Upfront costs reflect siting, permit, engineering, facilities, technology and testing

Annual Costs include O&M, carrying costs of fuel storage, technology and air permit testing

Present value of lifetime costs of technical option reflect assumed lifetime and discount rate

Cost of technical options are normalized in terms of costs per kW-month

7In the sections that follow, we summarize results for each of the infrastructure options identified above. Table C1 summarizes the assessment of options to mitigate gas dependency and is equivalent to Table 3.

Table C1: Comparison of Options for Firming Gas-Dependent Resource Fuel Supply

Technology Option		Cost	Other Factors
Dual Fuel	Current Dual Fuel Capable	• $5,700 per MW	• Time to recommission or install is relatively brief • Long refill times may limit effectiveness over long curtailments • Operations limits and risks when switching to alternate fuels • Requires environmental permitting
	Under- or Unutilized Dual Fuel Capability	• $6,500 per MW (annualized, reflecting capital cost and annual expenditures)	
	No Dual Fuel Capability	• $15,000 per MW (annualized, reflecting capital cost and annual expenditures)	
Service from Existing LNG Facilities (Canaport, DOMAC)		• Not estimated – cost would reflect (1) foregone opportunity to sell LNG in higher-value markets; (2) carrying cost; (3) operating cost; and (4) transportation charge. • Rate would be subject to negotiation	• Could be subject to deliverability constraints without firm service (esp. for Canaport, requiring transport over Maritimes pipeline)
New LNG Storage		• $29,700 per MW (annualized, reflecting capital cost and annual expenditures)	• Long refill times may limit effectiveness over long curtailments
New Pipeline Capacity		• $9,700 to $32,700 per MW for upfront costs • Rates for firm service would exceed these annualized costs	• Requires purchase of firm service • Time lag between commitments for firm service and new service availability • Reduces transport costs during periods of elevated prices (when basis differential exceeds tariff rate)

Dual-Fuel Capability

All natural gas-fired units are capable – in theory – of dual fuel (DF) operation. However, they can differ significantly in the amount of work that would be required to establish operational DF capability and in the costs that would be incurred to establish and use DF capability. Existing facilities fall into three basic categories:

1. *Facilities that currently have DF capability* – such units require *on-going* costs to (a) actively maintain alternate fuel burners, including burner and air permit testing, and (b) maintain sufficient fuel supply for an adequate period of operation (from the perspective of reliability needs under natural gas curtailment or contingency circumstances). These annual on-going costs are estimated at roughly $1.5 million for a 260 MW facility, or $5,700 per MW. Absent market incentives to maintain this capability and a means to recover these on-going costs, DF capability has been, or likely will be, decommissioned.

2. *Facilities with decommissioned DF capability* – such units require the same on-going costs as category 1 units, once operational. However, these units would also incur up-front costs including modest technical upgrades, as needed, to bring alternate fuel burners back to operational status, as well as testing to obtain or reinstitute air permits, and to ensure burner operability. The extent of these technical upgrades likely varies across units in the ISO-NE fleet given the type of equipment and turbines, and time period since mothballing. The annualized cost of recommissioning and maintaining DF capability is roughly $2 million for a 260 MW facility, or about $6,500 per MW.
3. *Facilities with no DF capability* – such units require the same on-going costs as category 1 units, once operational. However, these units would also incur up-front costs involving major technical upgrades to add alternate fuel burners and fuel storage capability, including testing of new burners and acquiring necessary permits. The annualized cost of developing and maintaining DF capability is are estimated at roughly $4 million for a 260 megawatt (MW) unit, or about $15,000 per MW.

Table C2 presents a summary of the cost estimates and assumptions used to develop these estimates, including up-front costs, annual costs, and present value cost per kW-month. Cost estimates reflect multiple data sources, including publicly available data and data provided by ISO-NE. Results range from approximately $5,700 per MW-year for units with DF capability, to $15,000 per MW-year for units with no DF capability, including levelized capital costs of installing new infrastructure.

Table C2. Cost and Technical Assumptions Regarding Dual Fuel Capability

	Dual Fuel		
	Dual Fuel Capable	**Under- or Unutilized Dual Fuel Capability**	**No Dual Fuel Capability**
Capacity (MW)	260	260	260
Upfront Costs			
Unit Cost ($/MW)		3,600	81,000
Total Development Cost ($)		936,000	21,060,000
Testing ($)		979,050	979,050
Total Upfront Cost ($)	0	1,915,050	22,039,050
Annual Costs			
O&M ($)	200,000	200,000	200,000
Annual Testing ($)	979,050	979,050	979,050
Fuel Carrying Cost ($)	307,862	307,862	307,862
Days Fuel Supply	3	3	3
Fuel Cost ($/MMBtu)	22.8	22.8	22.8
Total Annual Costs ($)	1,486,912	1,486,912	1,486,912
Lifetime (Years)	20	20	20
Discount Rate	9%	9%	9%
Present Value ($)	13,573,340	15,488,390	35,612,390
Present Value per MW ($)	52,205	59,571	136,971
Annualized Cost per MW ($)	5,719	6,526	15,005

There are a number factors related to timing, deployment, and operational characteristics that are important to consider with respect to DF capability, and differences between DF options, including the following:

- The actions needed to re-commission DF capability at units with mothballed or unused capability can likely be performed relatively quickly – burner upgrades are typically fairly limited in scope; there are relatively few barriers to securing sufficient fuel supply (other than cleaning unused storage tanks and securing cost recovery for fuel carrying costs); and minimum testing time is needed to maintain burner operability and permit status. There is more than sufficient time for resources to implement these technical changes in time for a commitment period three years ahead.
- Actions to install DF capability at units that do not have it are more involved and would require additional time – including development, permitting, and construction activities. However, there is more than sufficient time for resources to implement these technical changes prior to a commitment period three years ahead.
- In some cases there are or would be variations in output and risk of outage when actively switching from gas- to oil-firing. Some units – in particular those burning heavy fuel oil as a secondary fuel, need to power down before switching, and thus would provide less flexibility than units that can switch on the fly. In addition, there is an increased risk of outage with switching, particularly when alternate fuels are used infrequently.
- It is anticipated that regulatory limits on oil firing to address air quality concerns would generally allow for sufficient operability of DF units to cover electric system reliability needs. While some units may only be allowed to operate on oil when gas is unavailable, for most units, environmental permits typically set operational limits based on the annual number of hours operated (based on continuous operation at full output).
- Storage capacity (relative to burn at continuous full output) and storage refilling methods and rates can be an important element of maintaining resource availability, particularly during winter cold-snap conditions. DF units can have very different capacities and refill rates.
- Generally speaking, facilities served by oil pipelines or rail would be able to maintain burn if needed, and/or refill relatively quickly. But most facilities are served by truck refills, which can require days or weeks to refill to storage representing three days of continuous output.[72] For example, assuming tanker truck capacity of 9,000 gallons (generally on the high end) and representative heat rates, it would take 20 trucks per day to support continuous output of 130 MW.

[72] Three days of continuous output was chosen only to construct a representative calculation. Market performance obligations and/or reliability needs could require less than three days of continuous output.

New and Existing LNG Storage Capability

There are two options tied to liquefied natural gas that have been identified as opportunities to firm up natural gas fuel supply to natural gas-fired generating facilities in New England: (1) the construction of new land-based LNG storage facilities with liquefaction capability dedicated to providing backup gas fuel supply to power plants,[73] and (2) new services associated with spare capacity – to the extent it exists – at the two major LNG terminals serving the region (Distrigas of Massachusetts Corp, or DOMAC, located in Boston, and Canaport, located in Canada).

New LNG Storage Capacity

Estimated costs of new LNG storage capacity reflect the costs of three recently-sited facilities of roughly equal storage capacity. These facilities offered a combination of size, performance (vaporization and liquefaction), and cost that would be technically appropriate for providing backup fuel supply for gas-fired generators.

Table C3: Cost and Technical Assumptions Regarding New LNG Storage

Capacity	
LNG Volume (cubic meters)	60,000
NG Energy Capacity (MMBtu)	1,262,400
Flow capabilities	
Maximum vaporization rate (MMBtu / day)	91,300
Max MW per Day (given vaporization rate)	543
Maximum liquefaction rate (MMBtu / day)	6,333
Max MW Refill per Day (given liquefaction rate)	38
Variable Operating Costs	
Liquefaction cost ($ / MMBtu)	1.6
Storage and vaporization cost ($ / MMBtu)	0.4
Backup Fuel Supply Capability	
MW-Days of Backup Fuel Supply Stored	7,514
Max MW per Day (full output, given liquefaction rate)	543
Days to Refill (Liquefy) Sufficient Supply for Max MW per Day	14
Assumed Heat rate (Btu / kwh)	7,000

[73] With respect to new LNG storage, we focus on on-land facilities with liquefaction capability similar in size to many peak-shaving LNG storage facilities in existence today. We do not review facilities without liquefaction, as refill rates for storage without liquefaction are estimated to be too slow to provide a reliable back-up fuel supply. We also do not review new large-scale LNG terminals given the demonstrated and likely barriers to the siting of such facilities within New England.

The cost of a new LNG storage facility includes up-front development costs, annual operating costs, and the carrying cost of the stored fuel. Our estimates are based on the three facilities reviewed, sized to a generic facility with (a) a vaporization rate sufficient to provide backup fuel supply for approximately 540 MW of capacity; (b) 60,000 cubic meters (cm) of storage, equivalent to roughly 14 days of operation at the assumed vaporization rate; (c) a liquefaction rate that would be sufficient to refill enough supply to operate the facility (540 MW) for one day, in 14 days. Technical assumptions based on these three facilities are reported in Table C3.

Based on the recently-completed facilities, up-front costs range from $1,850 to $2,450 per cm of storage, amounting to approximately $128 million for the generic facility, including siting, permitting, engineering, and capital costs. Variable costs include fuel carrying costs and operating costs related to liquefaction, storage and regasification. This translates to a cost on the order of approximately $30,000 per MW-year, as shown in Table C4.

Table C4: Estimated Cost of New LNG Storage

Capacity (MW)	543
Upfront Cost	
Project cost ($)	127,666,667
Cost per cubic meter	2,128
Annual Costs	
O&M ($)	1,500,000
Carrying Cost ($)	633,920
Initial Fuel Cost (including liquefaction) ($)	7,043,561
Total Annual Costs ($)	2,133,920
PV	
Lifetime	20
Discount Rate	9%
Present Value ($)	147,146,257
Present Value per MW ($)	270,988
Annualized Cost per MW ($)	29,686

There are a number of factors related to timing, deployment, and operational characteristics that are important to consider with respect to LNG storage capability, including the following:

- Siting and development of a LNG storage facility could require multiple years, even under relatively easy siting conditions. Storage facilities of this size are modest-sized industrial facilities, so in some cases and/or locations opposition to siting at the local level could further lengthen the development timeline.
- The mix of liquefaction and vaporization rates introduces certain constraints on the market value of such facilities, and also on their reliability benefit. At the assumed (and achievable) vaporization rate, it would take between 7 and 20 days to fully discharge the tank. However, the liquefaction rate limits the ability to refill the tank after discharge. Specifically, it could take more than 190 days to fully refill the tank after discharge. Consequently, such a facility could

provide backup fuel for an extended curtailment (or multiple shorter curtailments), but that backup capability could be significantly limited for subsequent curtailments after full discharge.

Existing LNG Facilities

With respect to the existing DOMAC and Canaport facilities, it has been suggested that backup fuel supply to electric generators could be provided through arrangements to essentially store fuel and inject it into the pipelines upon request by electric generators from these two facilities.[74] Reliance on such services would require excess storage and regasification capacity at the terminal in question, and delivery service on Algonquin or Tennessee to the gas-fired generator's connection point on the pipelines. In addition, for Canaport service there would need to be delivery service on the Maritimes and Northeast pipeline. The stored gas, and the capacity to inject and deliver it, would need to be available as and when needed by the gas generator.

In this case, there are essentially no up-front costs. All services would be on existing facilities to the extent capacity exists. An estimate of annual costs can be derived by estimating (1) the opportunity cost of storing LNG instead of selling it in higher-value markets (i.e., Europe); (2) the carrying cost reflecting interest on the value of stored fuel; (3) the operating cost required to cool and store LNG at the facilities (including any lost fuel due to "boil off") and (4) if firm service is required to meet reliability requirements, a transportation charge for moving gas from storage to delivery point.

We have not attempted to estimate the type and cost of pipeline transportation charges, given the uncertainty around the type of service and rate that would be charged within the constraints of existing pipeline capacity. We have also not attempted to estimate the cost associated with service from existing LNG facilities due to uncertainty about the avoidable variable costs of storing incremental quantities of LNG supplies for use by gas-fired generators, and uncertainty about the rates the LNG facilities would charge for storage and release service for gas-fired generators. These rates would be subject to negotiations between generators and existing LNG facilities, which would reflect many factors, including the next-best options available to generators to storage and release service from an existing LNG facilities (such as foregoing service or developing dual fuel capability). Public information provided by existing LNG facilities on illustrative costs of such service suggests that this service would be more expensive than incremental development of dual fuel capability.[75] To the extent that resources can obtain service at terms that are less costly than dual fuel capability, the estimates of the quantity of incremental resources that address fuel dependency risks as a result of FCM PI would tend to be understated.

[74] In theory, these same services could be supplied by the offshore Neptune and Northeast Gateway terminals, through tankers "parked" at the intake pipes, or from existing local gas distribution company (LDC) peak shaving storage capacity. However, we did not review this separately given the potentially prohibitive costs of using tankers (on top of the other costs that would be faced by Canaport or DOMAC), and given the dedication of LDC storage facilities to serve natural gas LDC customers on peak.

[75] For example, see the illustrative terms and conditions for Call Option Service from the Canaport Facility provided by Repsol. Vince Morrisette, Repsol, "Gas Supply Peaking Option from Canaport LNG," ISO-NE Markets Committee, May 13, 2013.

New Interstate Pipeline Capacity

Relatively little firm service is available on the primary pipelines serving New England, so additional firm natural gas supply will likely require the construction of additional pipeline capacity. Increased natural gas pipeline capacity could support the transport of additional fuel supplies to the region, and so would reduce the risk of curtailment to gas-fired generators, relative to current market conditions. Additional pipeline capacity to provide firm gas supply can be achieved through various changes to the interstate pipeline system to relieve pipeline congestion or add incremental capacity, ranging from new compressor stations along existing pipe, to looping, to the construction of new pipelines from key gas sources (e.g., the Marcellus Shale region). The cost of various changes are difficult to identify absent engineering studies, and depend on the extent to which lower-cost technical changes to expand the capacity of the existing pipeline assets have already been exhausted.

The range of potential upfront costs to increase pipeline capacity from Marcellus and other lower-cost natural gas reserve regions is wide, and depends on the location of constraints being relieved, and/or the overall size and route of the project. Figure C2 provides estimates of the underlying capital costs of recently developed pipelines in the New England region in terms of the dollars per MW of firm service to gas-fired electricity generators. In addition to up-front costs, annual costs are incurred for operations and maintenance on the pipeline system. This estimate, based on an assumed increase in pipeline capacity of nearly 400,000 dekatherms per day, is approximately $1.17/kW-mth of equivalent electrical generating capacity.

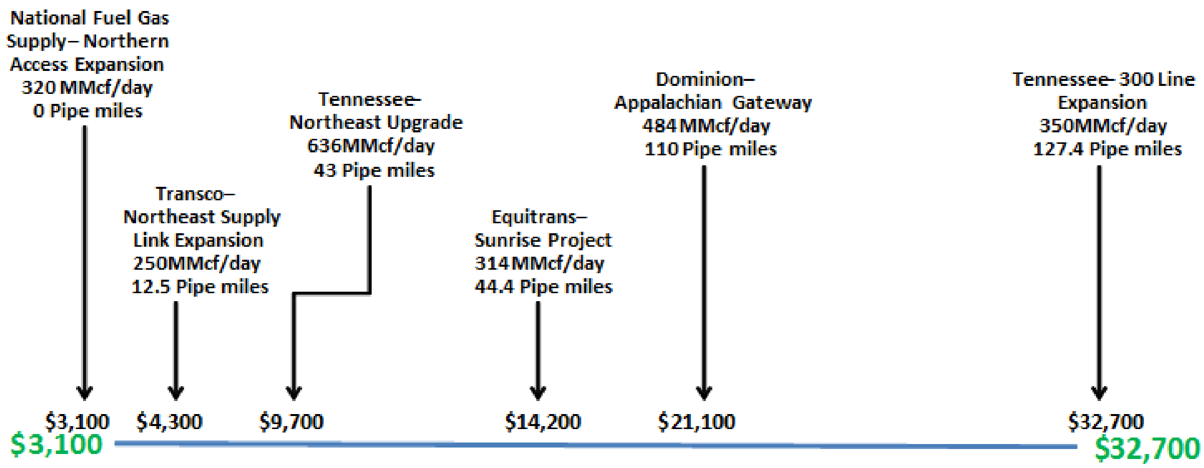
Ignoring the expansion projects, the annualized cost of upfront capital investments ranges from $9,700 per MW to $32,700 per MW (reflecting generation at a heat rate of 7,000 BTU per kw). These costs are comparable to those estimated by Black and Veach in a recent study for the New England States Committee on Electricity (NESCOE).[76] Total costs would account for additional factors such as annual operating expenditures.

Costs in Figure C2 do not reflect the rates that would be charged to generators for firm service. These rates would be higher than the costs reflected in these tables due to a variety of factors such as annual expenditures included in rates, differences in discount rates, and delays between when costs are incurred and when cost recovery begins from pipeline construction. Cost estimates also do not reflect potential reduction in gas transportation costs during periods of tight gas supply, particularly when the basis differential exceeds the tariff rate, or the ability of new pipeline to lower power system costs during such periods when supply from such regions would otherwise be constrained.

Assuming actual project costs would be toward the upper end of costs represented in Figure C2, and considering differences between estimates of annualized upfront costs and actual rates charged for firm service, we conclude that firm service on new pipelines is likely to be a more costly option for market participants to address gas dependency risks. To the extent that resources can obtain firm service at rates that are less costly than dual fuel capability, the estimates of the quantity of incremental resources that address fuel dependency risks as a result of FCM PI would tend to be understated.

[76] Black & Veatch, "New England Natural Gas Infrastructure and Electric Generation: Constraints and Solution", prepared for the New England States Committee on Electricity, April 16, 2013.

Figure C2: Capital Costs of Recent Northeast Pipeline Projects



There are a number factors related to timing, deployment, and operational characteristics that are important to consider with respect to the reliability and economic value of increasing pipeline capacity, including the following:

- The timeline for new pipeline capacity siting, permitting, and construction is on the order of several years. Consequently, this is not an option that can provide meaningful power system reliability benefits for at least several years.
- Under current FERC rules and past practices for funding new pipeline capacity, new projects typically will not go forward without up-front financial commitments from customers to take firm delivery service for all – or most – of the new capacity. Entering into such long-term financial commitments for natural gas transportation is challenging for electric generators under current market conditions.
- Current pipeline capacity firm commitments are held almost entirely by natural gas local distribution companies (LDCs) for the benefit of natural gas ratepayers, and with the guarantee that such capacity will be used to meet the need of LDC end-use customers for heating and process needs as necessary, particularly at the time of winter peak conditions. This means that while substantial amounts of such capacity may be released to secondary markets for use by electric generators throughout the year, it cannot be counted on during winter peak or cold-snap conditions.

List of Sources Reviewed for Appendix C

Sources of information relied on for the Dual Fuel section include the following:

- ESS Group, "Dual-Fuel Generating Capacity and Environmental Constraints Analysis," Interim Report, prepared for ISO-NE, April 1, 2005.
- Conversations with ISO-NE staff.
- Settlement between NYISO and TransCanada, Ravenswood for recovery of on-going costs of maintaining dual fuel capability, April 2011.
- PJM Cost of New Entry (CONE), incremental cost for dual fuel capability on new generation units, 2011.
- Handy-Whitman Index of Public Utility Construction Costs.
- Analysis Group estimates based on these reports, and on data provided by ISO-NE.

Sources of information relied on for the New Interstate Pipeline section include the following:

- INGAA publication #17742 (sourced from North American Midstream Infrastructure Through 2035 – A Secure Energy Future, ICF International for INGAA, June 28, 2011).
- "2012 Worldwide Pipeline Construction Report," Pipeline & Gas Journal, January 2012.
- "Pipeline Costs in Shale Gas Regions," Ziff Energy Group, June 29, 2011; "Natural Gas Under Siege," Ziff Energy Group, April 2012.
- "Gas and Electric Infrastructure Interdependency Analysis," Prepared for MISO by EnVision Energy Solutions, February 2012.
- "Jobs & Economic Benefits of Midstream Infrastructure Development, US Economic Impacts Through 2035," Black & Veatch for INGAA, February 15, 2012.
- Black & Veach, "New England Natural Gas Infrastructure and Electric Generation: Constraints and Solution", prepared for the New England States Committee on Electricity, April 16, 2013.

Sources of information relied on for the LNG Storage section include the following:

- "CB&I Awarded Contract for Temple LNG Expansion Project," Pipeline & Gas Journal, December 2009.
- UGI LNG company website: http://www.ugilng.com/
- "LNG Facility Brings Positive Economic Change to Former Manufacturing Center," Pipeline & Gas Journal, November 2009.
- "LNG Peakshaving Facility, Connecticut, USA," CB&I company website, http://www.cbi.com/markets/project-profiles/lng-peakshaving-facility-connecticut-usa/
- "Mt. Hayes Liquefied Natural Gas Storage Facility, Terasen Gas (Vancouver Island) Inc.," Stakeholder Workshop for the CPCN Application, June 27, 2007.

- "Mt. Hayes LNG Storage Facility – In the Matter of an Application by Terasen Gas (Vancouver Island) In. for a Certificate of Public Convenience and Necessity," Submitted to British Columbia Utilities Commission, June 5, 2007".
- "West Coast LNG Projects and Proposals," California Energy Commission, Sept. 2011.
- "CB&I Awarded Contract for Temple LNG Expansion Project," Pipeline & Gas Journal, December 2009.
- Repsol, "A Potential LNG Solution for Maintaining Pipeline Deliverability During Peak Demand Periods," ISO NE / NGA Meeting, April 12, 2012.
- Vince Morrisette, Repsol, "Gas Supply Peaking Option from Canaport LNG," ISO-NE Markets Committee, May 13, 2013.
- EIA, "World LNG Shipping Capacity Expanding," Report #DOE/EIA-0637, 2003.
- Massachusetts gas utility resource plans and forecasts.
- Analysis Group estimates.