

Evaluation of Changes in the Minimum Offer Price

Rules on Financial Risk in New England

**Prepared By:**



**External Market Monitor**

**for ISO-NE**

**November 2021**

**Table of Contents**

[Preface iii](#_Toc86419514)

[Executive Summary 5](#_Toc86419515)

[I. Background and Scope of Study 7](#_Toc86419516)

[II. Impact of MOPR on Financial Risk for Investors 9](#_Toc86419517)

[A. Principles of Capacity Market Design 9](#_Toc86419518)

[B. Market Risk with and without Out-of-Market Entry 10](#_Toc86419519)

[C. Conclusions 15](#_Toc86419520)

[III. Study Methodology 17](#_Toc86419521)

[A. WACC under the Status Quo MOPR 17](#_Toc86419522)

[B. Estimated Impact of MOPR Elimination on the WACC 18](#_Toc86419523)

[C. Conclusion 29](#_Toc86419524)

[IV. Model Inputs 31](#_Toc86419525)

[A. Principles for Determining Model Inputs 31](#_Toc86419526)

[B. Model Inputs 31](#_Toc86419527)

[V. Results and Conclusions 43](#_Toc86419528)

[A. Results 43](#_Toc86419529)

[B. Conclusions 50](#_Toc86419530)

**List of Figures**

[Figure 1: Capacity Price Formation in a Competitive Market 11](#_Toc86727530)

[Figure 2: Capacity Prices in a Market with Policy Intervention A 12](#_Toc86727531)

[Figure 3: Capacity Prices in a Market with Policy Intervention B 13](#_Toc86727532)

[Figure 4: Capacity Prices in a Market with Policy Intervention B and MOPR 13](#_Toc86727533)

[Figure 5: Illustrative Revenue Distributions in the MOPR and No MOPR Cases 22](#_Toc86727534)

[Figure 6: Assumed Relationship between Cost of Debt and Rating Case DSCR 24](#_Toc86727535)

[Figure 7: Summary of Modeling Steps 25](#_Toc86727536)

[Figure 8: Peak Load Forecast Scenarios 33](#_Toc86727537)

[Figure 9: Targets for Solar and Storage Resources (nameplate capacity) 37](#_Toc86727538)

[Figure 10: Qualified Capacity from Subsidized Energy Storage and Solar Resources 38](#_Toc86727539)

[Figure 11: NREL’s 4-hour Battery Cost Projections 39](#_Toc86727540)

[Figure 12: Distribution of EAS Revenues at Various Surplus Levels 41](#_Toc86727541)

[Figure 13: Estimated Hours of System Operating Reserve Deficiencies for 2024/25 42](#_Toc86727542)

[Figure 14: Distribution of Revenues to Reference Unit with and without MOPR 46](#_Toc86727543)

[Figure 15: Iterations to determine COE and COD in No MOPR Case 49](#_Toc86727544)

[Figure 16: Change in ATWACC with Leverage 50](#_Toc86727545)

[Figure 17: Distribution of Revenues to Reference Unit 51](#_Toc86727546)

List of Tables

[Table 1: State Procurement Targets for Key Technologies 14](#_Toc86727547)

[Table 2: Fitch Ratings Guidance regarding Indicative Coverage Ratios 20](#_Toc86727548)

[Table 3: Illustrative Calculation of DSCR in the MOPR and No MOPR Rating Cases 23](#_Toc86727549)

[Table 4: DSCRs in Base and Rating Case 48](#_Toc86727550)

Preface

Potomac Economics serves as the External Market Monitor for ISO-NE. In this role, we are responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by ISO-NE.[[1]](#footnote-2) In this report, we provide our evaluation of the impact of eliminating MOPR on the financial risk and how certain market parameters need to be adjusted to provide the required incentives to merchant investors.

The principal authors of this report are:

David B. Patton, Ph.D.

Pallas LeeVanSchaick, Ph.D., and

Raghu Palavadi Naga

Executive Summary

ISO-NE is working with its stakeholders to eliminate or modify the Minimum Offer Pricing Rule (“MOPR”) in time for the Forward Capacity Auction 17 (“FCA-17”). Eliminating MOPR would lower the barriers to participation in capacity markets by resources that are supported by the New England states. However, an important consequence of eliminating the MOPR is an increase in the financial risk for merchant resource owners. The ISO requested the EMM evaluate this risk and how it can be accounted for in the market. This report describes our assessment of the increase in the financial risk to merchant investors if the MOPR is eliminated.

The capacity market is designed to provide efficient incentives for the investment needed to satisfy resource adequacy needs. In other words, as capacity margins fall and new investment is needed to satisfy New England’s resource adequacy requirements, an investor must find it attractive to invest in a new resource. This requires that the investor expect future capacity revenues to cover its “Cost of New Entry” less revenues expected from the energy and ancillary services markets (i.e., “net CONE). As the volatility of future capacity revenues increase, the risk facing the investor and its net CONE increase.

One key factor that increases future revenue volatility and risk is out-of-market investment in resources are subsidized and result in a capacity surplus. Large quantities of such investments are planned by various states in New England to achieve decarbonization goals. The status quo MOPR moderates the price effects of such investment, reducing the associated risks to private investors in new resources. Accordingly, elimination of the MOPR provisions is likely to increase the risk facing merchant investment in New England. The purpose of this study is to recommend a change in the capacity market to account for this increased risk.

Higher financial risk affects key parameters that are used to determine the sloped capacity demand curves. The height of the demand curve depends on the Net CONE of a generic potential new entrant. The height is set to motivate investment needed to achieve a target level of reliability. Higher price volatility increases investment risk, which raises the cost of capital. Consequently, the Net CONE of the reference unit increases as price volatility increases.

Recent CONE studies have estimated the cost of capital of a new entrant based on a review of historical returns required by investors in power generation assets operating in regions with competitive wholesale markets. Each of these markets is either in a state jurisdiction with limited policy intervention or has limited the price effects of subsidized entry with a MOPR. Hence, the available historic data does not reflect the returns an investor would expect in a competitive power market without a MOPR and high levels of policy-driven investment. Hence, it is important to account for the effects of eliminating the MOPR provisions on the WACC.

To account for the incremental effects of eliminating the MOPR provisions on the WACC, we estimate the change in revenue volatility for the reference unit between the following two cases under long-term equilibrium conditions:[[2]](#footnote-3)

* Case 1: Under the status quo MOPR rules, and
* Case 2: After elimination of MOPR rules.

Monte Carlo techniques are used to estimate the distribution of revenues for the reference unit in each of the two cases above. Changes in the volatility of the revenue distribution, as measured by metrics such as standard deviation and financial performance under downside market conditions, affect investors’ Cost of Equity (“COE”) and Cost of Debt (“COD”) that together determine the WACC. We use the Capital Asset Pricing Model (“CAPM”) and criteria employed by the credit ratings agencies to quantify the changes in the COE and COD.

To the extent possible, we maintain consistency with the recent CONE study in developing assumptions for our analysis. However, since the CONE Study does not explicitly characterize the volatility of revenues to the reference unit, we developed and presented to stakeholders our assumptions regarding several drivers of revenue volatility for the reference unit that are affected by state policies. Our scenarios regarding state policies are derived primarily from key documents supporting legislation and/or regulations.

Ultimately, based on the results of our model, we find that:

* There is a considerable difference in the volatility of revenues to the reference unit with and without the MOPR provisions.
* Removing the MOPR provision increases the After-Tax Weighted Average Cost of Capital (“ATWACC”) by 225 basis points.
* Hence, we recommend an ATWACC of 10.51 percent to compensate investors for the higher investment risk in the No MOPR case.

This increase in ATWACC translates into a Net CONE of $8.66/kW-year (2025$), which is 16 percent higher than the current value of $7.47/kW-month. In addition, the Payment Performance Rate (“PPR”) should be increased to $10,846/MWh from $9,337/MWh, to reflect the higher Net CONE of the reference unit.

1. Background and Scope of Study

New England relies on competitive wholesale market incentives to motivate investors to build new supply and maintain existing resources to satisfy resource adequacy needs. In recent years, New England states have increasingly promoted investment in clean resources to achieve ambitious environmental goals through long-term contracts and other out-of-market revenue streams. ISO-NE’s Minimum Offer Pricing Rules (“MOPR”) have moderated the price effects of out-of-market investment by imposing offer floors on resources receiving such revenues in some cases. In other cases, resources receiving out-of-market revenues have been able enter the market and sell capacity after participating in ISO-NE’s Substitution Auction for sponsored resources.

The MOPR has helped ensure that out-of-market subsidies do not undermine the market’s ability to attract investment needed for resource adequacy. However, the status quo MOPR could become a barrier to or increase the costs of States achieving their public policy goals. Accordingly, ISO-NE is working with its stakeholders to eliminate or modify the MOPR in time for FCA-17.

An important consequence of eliminating the application of the MOPR to public policy resources will be an increase in the financial risk for merchant resources. The increase in financial risk will result from increased volatility of market revenues after the MOPR is eliminated. This occurs because subsidized resources will be able to enter the market and sell capacity even when they are not economic and are contributing to a substantial capacity surplus. As a result, investors are likely to require a higher return on capital for merchant supply resources in the ISO-NE markets. The ISO requested the EMM evaluate this risk and how it can be accounted for in the market.

This report describes our assessment of the increase in the financial risk to merchant investors due to the elimination of the MOPR, and it is organized as follows:

Section II discusses the key drivers of financial risk for investors in capacity resources, and how the MOPR tends to reduce this risk.

Section III provides an overview of our methodology for quantifying the increase in financial risk due to elimination of the MOPR.

Section IV describes our principles for determining the inputs and the key assumptions for the study, and

Section V discusses the results and conclusions of our study.

1. Impact of MOPR on Financial Risk for Investors

When entry and exit of supply occurs that is not in response to market signals, i.e., occurring outside of the market through power purchase agreements, prices and other market outcomes become more volatile and difficult to forecast. MOPR provisions reduce this volatility by limiting the quantity of out-of-market new resources that will clear in the capacity market. Hence, capacity price volatility will likely increase when MOPR is eliminated, and merchant investors will demand a higher return for investing in New England. Since developers of intermittent generation and energy storage resources rely on a mix of out-of-market revenues and wholesale market revenues, even these developers will demand a higher return on investment.

In this section, we discuss:

The principles of capacity market design, including the role of capacity market and the relationship between key market design parameters and price stability (subsection A),

How price stability is affected by out-of-market entry (subsection B), and

Our conclusions regarding how MOPR affects financial risk for investors (Subsection C).

1. Principles of Capacity Market Design

The purpose of the capacity market is to provide efficient incentives for the investment needed to satisfy resource adequacy needs. ISO-NE is responsible for satisfying a one-day-in-ten-years reliability standard. Energy and ancillary services markets typically do not provide adequate revenues to sustain reserve margins at that required level of reliability. The shortfall in revenue (after accounting for net revenues from the sale of energy and ancillary services) is called the “missing money”, which the capacity market is designed to provide.

Capacity prices are primarily determined in annual auctions based on the supply offers from capacity resources and the demand curves. Supply and demand in the capacity auctions change from one year to next, while supply investments are long-lived (i.e., >20-year) assets that depend on revenues over the long-term. Hence, annual capacity auctions provide limited revenue certainty, making long-term expectations of auction clearing prices an important driver of investment.

The capacity demand curve has a downward-sloping shape so that as the capacity surplus increases, prices fall, and vice versa. This promotes the capacity price stability by encouraging new entry when needed for resource adequacy and discouraging entry when additional supply would provide less reliability value. The capacity demand curve is set by two key parameters:

*Slope of Demand Curves* - ISO-NE sets the slope of the demand curve in proportion to the marginal reliability value of capacity.

*Height of Demand Curves* - The height of the sloped demand curve depends on the Net CONE (“Cost of New Entry”) of a generic potential new entrant (i.e., the demand curve unit). The height is set in order to motivate investment needed to achieve a target level of reliability, since a merchant investor must expect to recover Net CONE over the long-run as prices fluctuate. Key factors that affect the Net CONE include the estimated energy and ancillary service revenues, capital expenditures, economic life, and the cost of capital. Hence, higher price volatility increases investment risk, which raises the cost of capital and, consequently, Net CONE.

In the next subsection, we discuss how the volatility of revenues and the investment risk is influenced by out-of-market entry.

1. Market Risk with and without Out-of-Market Entry

Eliminating MOPR should enable a greater level of participation in the capacity market from state-sponsored resources that would have otherwise been subject to an Offer Floor Price. Increased out-of-market entry would result in higher market risk to revenues of merchant resources and other resources that rely at least partly on wholesale market revenues. The first part of this subsection illustrates how policy-driven investment and merchant investment tend to affect price volatility differently. The second part of the subsection highlights the tendency for state policy goals to change significantly over time with recent examples from New England.

In a market where new entry and exit are motivated only by market price signals, gradual demand growth and attrition of older inefficient supply leads to gradual new entry, resulting in predictable fluctuations in capacity surpluses and low price volatility. New supply investment is often lumpy, leading to some transitory periods of lower prices, so developers must consider such risks before making an investment. However, large and sustained surpluses are less likely. Overall, revenue forecasts reflect modest uncertainty because market responses generally dampen the effects of shocks.

In contrast, in a market with substantial out-of-market entry and exit, state policies (e.g. subsidized generation investment, electrification, etc.) may lead to large shocks in supply and demand. State-sponsored resource entry causes a larger shock to the system (relative to merchant developers) because the decisions about the timing and/or quantity of new entry are: (a) less dependent on the market conditions, about which participants can develop reasonable expectations, and (b) more dependent on the characteristics of the policy support, which may or may not have been anticipated.[[3]](#footnote-4) Since the investment and retirement responses to these shocks can take years to materialize, out-of-market entry can significantly affect prices in the short to medium term. The MOPR provisions tend to moderate the price effects of out-of-market entry and exit.

* + 1. Effects of Policy-Driven Investment and Merchant Investment on Price Formation

The following four figures illustrate how price volatility varies across markets according to the scale of out-of-market changes in supply and demand.

Figure 1 shows how the prices fluctuate over a five-year period around the Net CONE in a competitive market. In year 1, approximately 32,600 MW of existing supply is offered into the capacity market with delist bids of less than $5.30, leading to a clearing price of approximately $7/kW-month (see “P1”). In this scenario, a modest amount of load growth increases the demand every year (by ~0.8 percent), leading to a rightward shift in the demand curve each year from year 1 to year 5. A small amount of existing supply (~50 MW) is lost to attrition every year, contributing a small leftward shift to the existing supply from each year to the next. New supply resources offer capacity in the first year: 350 MW at $6.75, 350 MW at $7.00, 350 MW at $7.25, etc., and the Net CONE falls slightly for each new resource each year until it clears the market. One 350 MW project clears in each year from year 2 to year 5, leading the existing supply to shift right in each year after year 2. These conditions combine to produce clearing prices that fluctuate around the Net CONE as prospective new entrants make decisions to invest (or not) that naturally push prices towards Net CONE.

Figure 1: Capacity Price Formation in a Competitive Market

Gradual Demand Growth & Competitive Merchant Entry



Figure 2 shows how the prices would tend to increase as a result of higher demand growth due to policies to electrify the demand sector (e.g., programs to install electric vehicle charging stations and convert residential gas furnaces over to heat pumps) and reduced supply investment due to policies to limit new investment in conventional resources. Figure 2 is similar to the previous figure, but demand growth is much faster (~2.5 percent per year) and the net cost of new entry rises 2 percent each year. This combination of policies would generally lead to higher and slightly more volatile prices than those shown in Figure 1.

Figure 2: Capacity Prices in a Market with Policy Intervention A

High Electrification & Limited New Fossil



In contrast, Figure 3 illustrates the outcomes in a market with substantial out-of-market entry that is insensitive to capacity market conditions (i.e., where out-of-market entry exceeds demand growth for a sustained period of time). Each year after year 1, it shows nearly 1 GW of new supply entering the market as price-takers despite the steep year-over-year declines in capacity prices. In year 2, the clearing price (“P2”) is set at the going-forward cost of existing capacity, but prices continue to fall each year as higher cost existing resources leave the market. This scenario illustrates how very low prices can occur for a sustained period when the amount of out-of-market entry exceeds the amount of price-responsive supply in the market.

Figure 4 illustrates how the MOPR provisions can reduce this downside risk to investors by incorporating MOPR rules (with a Substitution Auction) into the scenario shown in Figure 3. In each year, the clearing price is set by unsubsidized resources clearing, while the substitution auction allows new subsidized resources to enter the market as long as their capacity is matched by an equal amount of retirement, causing prices to remain much closer to competitive levels.

Figure 3: Capacity Prices in a Market with Policy Intervention B

High Out-of-Market Investment in Supply



Figure 4: Capacity Prices in a Market with Policy Intervention B and MOPR

High Out-of-Market Investment in Supply with a MOPR



* + 1. Potential Out-of-Market Entry in New England

The New England states have set aggressive procurement targets in legislation and/or regulations for several different clean resource categories. In recent years, these procurement targets have significantly evolved in their scale, the timing of implementation, and the specific technologies that are targeted. As merchant investors consider whether to build new generation assets with a useful life extending past 2040, they must consider current targets and the likelihood that these will be modified over the time horizon of the investment.

The following table shows the states’ current procurement targets for key technologies that could have a considerable effect on the supply-demand balance in the capacity market. The table also shows how these targets have changed over time and/or the progress towards the targets.

Table 1: State Procurement Targets for Key Technologies



The quantity of sponsored policy resources is significant, so these procurements could have a large impact on the supply-demand balance in future years. However, the targeted quantities and the dates when resources must be procured or must begin operating have changed dramatically over time, making them difficult to predict for a prospective merchant investor. For instance:

OSW targets have grown significantly from 1.6 GW in 2016 to over 6 GW in a period of four years, with the possibility of additional increases in targets. In addition, the timeframe for the targets to be reached have also advanced.

No states in New England had large energy storage procurement targets prior to 2018. However, in the past four years, three states have adopted a total of 1,400 MW plus 1,000 MWh in explicit storage targets, and Massachusetts has adopted large but uncertain storage entry objectives under the SMART and Clean Peak Standard programs. We estimate that over 4 GW of energy storage could enter under *existing* state programs by 2030, but additional entry is possible.

While the original target date for a transmission line that would allow importation of 1.2 GW of hydropower from Quebec was late-2022, the line has not sold capacity through FCA-15, which is for 2024/25.

All of the above targets are likely to impact the supply-demand balance in future years. As demonstrated by the table above, the quantity and timing of the entry of sponsored policy resources has varied considerably. These changes would have been difficult to predict many years in advance. In the absence of the MOPR, the difficulty in predicting changes in these policy targets will lead to increased price volatility.

1. Conclusions

The capacity market is designed to provide efficient incentives for the investment needed to satisfy resource adequacy needs. In a competitive market, supply offers and capacity demand curves each contribute to price stability. Price-responsive supply offers moderate shocks to the market by responding to high prices with new entry and low prices with retirement. The demand curves also contribute to price stability because the sloped shape of the demand curve causes prices to increase as the capacity surplus falls, and vice versa.

Investors that rely on wholesale market revenues respond to supply and demand shocks in a manner that dampens their effects. However, high levels of investment that disregards wholesale prices may exhaust the capability of the market to respond to shocks, and policy-driven investment tends to increase these shocks to the market. The status quo MOPR reduces the resulting price effects, while elimination of the MOPR will tend to increase investment risks. Accordingly, elimination of the MOPR provisions is likely to increase the risk of investing in New England on a merchant basis. We discuss our methodology for quantifying this increase in risk and the associated increase in the cost of capital in the next section. This recommended increase in the cost of capital will allow the capacity market to facilitate investment and retirement decisions that will satisfy New England’s resource adequacy needs.

1. Study Methodology

Recent CONE studies have estimated the cost of capital of a new entrant based on a review of historical returns required by investors in power generation assets operating in regions with competitive wholesale markets. Each of these markets is either in a state jurisdiction with limited policy intervention or has limited the price effects of subsidized entry with a MOPR. Hence, the available historic data does not reflect the returns an investor would expect in a competitive power market without a MOPR and high levels of policy-driven investment. Hence, it is important to account for the effects of eliminating the MOPR provisions on the WACC.

This section of the report describes our model for estimating how future price volatility would be affected by *a change* in market rules (i.e., elimination of MOPR). Specifically, our model estimates how a change in price volatility resulting from MOPR elimination would change:

The cost of equity using the Capital Asset Pricing Model (“CAPM”); and

An investor’s cost of debt based on criteria employed by credit rating agencies.

In this section, we: (a) summarize how the WACC was estimated under status quo rules, i.e., with MOPR in place (subsection A), and (b) discuss our methodology and the modeling steps for estimating WACC if MOPR is eliminated (subsection B).

* 1. WACC under the Status Quo MOPR

The ISO recently estimated the cost of capital parameters as part of its estimates for the Net CONE of the reference unit for FCA-16. The consultants estimated a COE of 13 percent, a COD of 6 percent, and a debt ratio of 55 percent for a new merchant entrant in the ISO-NE control area. The study was conducted in 2020 based on a review of historic data and prevailing financial market conditions. Accordingly, the WACC developed as part of the 2020 CONE study reflects the existence of the current MOPR provisions.

The consultants estimated the WACC parameters in the CONE study in the following manner:[[4]](#footnote-5)

The COE was estimated using the results of the CAPM that considered the historical returns on equity for a peer group of IPPs.

The COD was determined based on a review of debt ratings of IPPs and historical bond yields for B and BB rated companies.

The leverage ratio was estimated based on a review of the capital structure of a peer group of companies over a historical period.

* 1. Estimated Impact of MOPR Elimination on the WACC

As noted in the introduction to this section, there are no available historic comparables for a competitive power market that motivates merchant new entry without a MOPR. Accordingly, a new approach is needed for estimating the effect on the WACC for new entrants of eliminating the application of the MOPR provisions to public policy resources.

Our approach relies on quantifying the *change* in revenue volatility for the reference unit (under long-term equilibrium conditions) between the following two cases: (a) the status quo with the MOPR rules, and (b) after elimination of MOPR rules. We use Monte Carlo techniques to estimate the distribution of revenues for the reference unit in each of the two cases above. The policy assumptions and other supply and demand inputs are identical between the two cases, so this approach isolates the effect of the MOPR rule change on price formation. Changes in the volatility of the revenue distribution imply that the COE and COD should also change. We use CAPM and criteria employed by the credit ratings agencies to quantify the changes in the COE and COD.

We describe the theory underlying our methodology for estimating the change in COE and COD in subsections 1 and 2 below. Subsection 3 describes each of the modeling steps involved in estimating the change in the WACC that would result from eliminating the MOPR.

* + 1. Revenue Volatility and Cost of Equity

As discussed in subsection A, the Capital Asset Pricing Model (“CAPM”) was used in the CONE study to estimate the COE, and we adopted this value in the MOPR case. In the CAPM framework, investors require a higher return on equity from an asset whose returns are more volatile relative to an asset whose returns are less volatile, even if the expected average return from both assets is the same. Specifically, the CAPM framework implies that, all else being equal, the return on equity required by investors varies in direct proportion to the volatility of returns on the asset (as measured by the standard deviation of returns).[[5]](#footnote-6)

Thus, we estimate the COE in the No MOPR case in the following manner:

*COENoMOPR = COEReg + COENoMOPR-P*

*COENoMOPR = COEReg + COEMOPR-P × StDevNoMOPR ÷ StDevMOPR*

where,

*COENoMOPR* is the cost of equity in the No MOPR case,

*COEReg* is the cost of equity for a regulated entity, which we derive from recent orders setting regulated ROEs,

*COENoMOPR-P* is the power market risk component of cost of equity with No MOPR,

*COEMOPR-P* is the power market risk component of cost of equity under the MOPR, which we derive as the difference between Merchant cost of equity under status quo conditions such that: *COEMOPR-P* = *COEMOPR* – *COEReg*,

*StDev* is the expected standard deviation of market returns in each case

In summary, this formulation bases the COE in the No MOPR case on the sum of two components:

*COEReg* which is an estimate of the risk associated with investing in a unit that does not face any power market risk. This risk is assumed to be the same in the MOPR and No MOPR cases.[[6]](#footnote-7)

*COENoMOPR-P* which is the component of the COE associated with the power market risk after the elimination of MOPR. We estimate this component by scaling up the power market risk component of the COE under status quo by the ratio of standard deviation of market returns in the two cases.

* + 1. Revenue Volatility and Cost of Debt

As discussed in section II, the wholesale market will experience supply and demand shocks that could have larger price effects after the MOPR is eliminated. In particular, the likelihood of experiencing periods of severely depressed wholesale prices is expected to increase. In addition to expected prices, credit rating agencies consider a variety of downside or stressed conditions when evaluating the ability of a project to satisfy its debt obligations and assigning a rating for it.[[7]](#footnote-8) Therefore, even if two projects have the same revenues on an expected basis, a project that faces a larger downside risk (i.e. the one whose revenues are likely to be lower under stressed conditions) would receive a lower rating, which would result in a higher COD.

While the Net CONE Study used historic data on publicly traded companies with balance sheet financing to estimate the cost of capital for merchant generation investments under the current market rules., our model uses principles of project finance to estimate how changes in the distribution of revenues would be expected to affect the cost of capital for merchant generation investments. The primary metric we use to analyze the ability of a project to satisfy its debt service obligations is the Debt-Service Coverage Ratio (“DSCR”), which is the ratio of a project’s operating income to its debt service payments.[[8]](#footnote-9) A high DSCR generally leads to a better credit rating, while a low DSCR leads to (a) a lower credit rating and/or (b) an increase in liquidity requirements for the project. We utilize the following guidance (Table 2) from Fitch Ratings regarding how a change in the expected DSCR of a project would affect its debt rating and COD. The table examines the ability of a project to cover its debt service under conditions “consistent with the expected bottom” of an economic cycle, which is known as a “Rating Case”.[[9]](#footnote-10)

Table 2: Fitch Ratings Guidance regarding Indicative Coverage Ratios[[10]](#footnote-11)



The table shows that as the DSCR in the Rating Case decreases, the project’s rating (and its COD) worsens. A merchant generator in a deregulated wholesale market would be analyzed using the row for “Full Merchant Exposure”. To develop the Rating Case DSCR and estimate the COD in the No MOPR case, we:

Adjust the revenue distributions (in both the MOPR and No MOPR cases) by increasing the fixed costs and reducing the heat rate of the unit to reflect worse than expected performance based on guidance from rating agencies,[[11]](#footnote-12)

Determine the portion (i.e., percentile range) of the revenue distribution where the DSCRs in the MOPR case correspond to the B+/BB- range (i.e., 1.27 to 1.53 based on the guidance in Table 2), which is the rating range assumed for developing the COD in the recent CONE study,

Estimate Rating Case revenue and DSCR in the No MOPR case based on the revenues from the same percentile range of the revenue distribution determined in the previous step, and

Map the estimated Rating Case DSCR in the No MOPR case to a specific COD using Table 2 and the yields for B and BB-rated corporate bonds.[[12]](#footnote-13)

In summary, we first the baseline level of market stress in the MOPR case that is associated with the COD from the CONE Study, and then we stress the project cash flows to a similar degree in the No MOPR case to determine the DSCR and COD in the No MOPR case.

To illustrate this methodology, consider Figure 5 which shows (a) the illustrative distributions of the total revenues for the reference unit in the MOPR case and in the No MOPR case before adjusting capital cost parameters, (b) the portion of the distribution where the revenues correspond to a B+/BB- rating (i.e. where the DSCR is between 1.27 and 1.53) in the MOPR case (which is labeled as “Rating Case Range”), and (c) the average and Rating Case revenues in the MOPR and No MOPR cases.

Figure 5: Illustrative Revenue Distributions in the MOPR and No MOPR Cases

Before adjusting WACC parameters



In the above figure, the DSCRs commensurate with a B+/BB- rating in the MOPR case correspond to approximately 5th to 12th percentile of the revenue distribution (shown as the Rating Case range). Although the average revenue across the 2000 realizations is the same in both MOPR and No MOPR cases, the average revenue in the Rating Case range is eight percent lower in the No MOPR case.

Table 3 illustrates the derivation of the Rating Case DSCRs in the MOPR and No MOPR cases. It shows that the Rating Case DSCR declines from 1.41 in the MOPR case to 1.10 in the No MOPR case. To map the Rating Case DSCR into a COD, we developed a function that relates these two parameters considering the corporate bond yields in the first half of 2020 and the Fitch Ratings guidance contained in Table 2.[[13]](#footnote-14)

Figure 6 shows: (a) our assumed COD as a function of the Rating.Case DSCR, and (b) the COD for a Rating Case DSCR of 1.10. As shown, we estimate the COD in the No MOPR case in our illustrative example to be 8.1 percent.

Table 3: Illustrative Calculation of DSCR in the MOPR and No MOPR Rating Cases



Figure 6: Assumed Relationship between Cost of Debt and Rating Case DSCR



* + 1. Estimating Change in WACC due to Eliminating MOPR – Modeling Steps

In this part of the subsection, we detail each of the steps used in the model for estimating the change in WACC that is due to MOPR elimination. Figure 7 shows a flowchart that summarizes these steps.

Figure 7: Summary of Modeling Steps



1. Develop Monte Carlo Realizations of the System in the MOPR Case

We use Monte Carlo simulation techniques to generate a probability distribution of the revenues to the reference unit and derive the relevant risk metrics in the MOPR case. We develop 2000 realizations of supply and demand curves and estimate the revenues to the reference unit (capacity, PFP and energy and ancillary services revenues) in each realization.[[14]](#footnote-15) In each realization, we assume that the sponsored policy resources are subject to an Offer Floor Price that is based on the resource’s Net CONE.

The sources of uncertainty in our model include uncertainty in the following variables:[[15]](#footnote-16)

Peak load forecast

Quantities of sponsored policy resources (offshore wind, energy storage, and solar resources)

Cost of energy storage resources

Existence of the NECEC line

Capacity import offers from NYISO

Quantity of feasible new fossil fuel-fired CTs

Number of shortage hours given a surplus capacity level, and

Energy and ancillary services revenues given a surplus capacity level

2. Adjust Supply to Move System to Long-term Equilibrium in the MOPR Case

The Net CONE used to set the capacity demand curves (and several of its input parameters such as energy and ancillary services revenue offset and number of shortage hours), is determined as the “missing money” of the reference unit under long-term equilibrium conditions. Accordingly, for the purpose of our analysis, we consider a wholesale market under long-term equilibrium conditions, where:

*Annualized Gross CONE of Reference Unit = Total Revenues of the Reference Unit*

However, the assumed characteristics of supply and demand may not result in adequate revenue to the reference unit on an expected basis. Hence, to model a system at long-term equilibrium, we solve for an adjustment to the supply stack that removes capacity from high-cost existing resources until the average revenue to the reference unit across the 2000 realizations equals its annualized Gross CONE based on its assumed COE and COD.

3. Derive Risk Metrics that Correspond to COE and COD in the MOPR Case

Based on the distribution of revenues across the 2000 Monte Carlo realizations in the MOPR case, we derive the financial risk metrics that correspond to the COE and COD under the status quo rules.[[16]](#footnote-17) Specifically:

We determine the standard deviation of the revenues of the reference unit, which is assumed to correspond to the power market risk component of the assumed COE (COEMOPR-P) in the MOPR case.[[17]](#footnote-18)

We determine the Rating Case range of the revenue distribution as the portion of the distribution (i.e., upper and lower percentile values) where the DSCR corresponds to the assumed COD (i.e., the COD determined in the CONE study).

4. Develop Monte Carlo Realizations of the System in the No MOPR Case

To develop the Monte Carlo realizations in the No MOPR case, we start with the supply curves for all the realizations from the MOPR case, and then we remove any mitigation that was applied to sponsored policy resources. We remove the mitigation by setting the offer floors of all sponsored policy resources to $0/kW-mo. All other inputs to the Monte Carlo simulation remain the same across the MOPR and No MOPR cases, except for the supply adjustment that is required to move the system to long-term equilibrium conditions.

5. Adjust Supply to Move System to Long-term Equilibrium in the No MOPR Case

Similar to the MOPR case, we remove capacity from higher-cost existing resources to ensure that the long-term equilibrium condition is satisfied in the No MOPR case also. Given the larger surplus in the No MOPR case, a larger quantity of existing supply (relative to the MOPR case) will have to be removed to set up the system under long-term equilibrium conditions.

6. Estimate Observed COE and COD in the No MOPR Case

We use the revenue distribution to estimate the observed COE and COD in the No MOPR case.

For COE, we calculate the standard deviation of the revenues in the No MOPR case and use the relationship discussed in subsection B.1 to estimate the observed COE in the No MOPR case.

For COD, we estimate the Rating Case DSCR in the No MOPR case based on the average revenues from the Rating Case range of the distribution determined in step 3 above, and we use the assumed relationship between Rating Case DSCR and COD (see Figure 6) to estimate the observed COD in the No MOPR case.

7. Evaluate Consistency of Observed COE and COD with Assumed Values underlying Revenue Distribution

If the observed values for COE and COD are higher than the initial assumed values in the No MOPR case, then the analysis is repeated using different assumed values of COE and COD. An increase in the assumed COE and COD affects both the supply and demand curves in the next iteration of the No MOPR case since:

(a) A higher WACC increases the Net CONE of the reference unit and, consequently, the capacity demand curve, and

(b) A higher WACC increases the capacity supply offers from new merchant resources.

Hence, the Monte Carlo simulation is repeated (by returning to step 4) using updated supply and demand curves based on the last observed COE and COD values. This is repeated until the observed COE and COD at the end of step 7 converge to the values assumed in step 4. Thus, we gradually adjust the COE, COD and the supply adjustment (see step 5 above) and iterate until the conditions below are satisfied:

The WACC used to calculate demand curve and supply offers is consistent with the WACC implied by volatility of revenues, and

The Gross CONE of reference unit equals the average total revenues of the reference unit.

8. Determine Optimal Debt Ratio and Finalize WACC

Given the increased likelihood of low prices in the No MOPR case, the COD in the No MOPR case tends to increase relative to the status quo. However, project developers can improve their debt rating and lower their COD by reducing leverage. This tends to reduce the overall WACC for the project.

While a lower debt ratio tends to lower the COD, it also affects other components of the WACC. So, the optimal value is chosen considering several trade-offs. Specifically, a lower debt ratio affects the overall WACC in the following ways:

It reduces the required debt service payments, improving its DSCR and debt rating. This tends to reduce the WACC.[[18]](#footnote-19)

It increases the equity share of capital, and since COE is higher than COD, this tends to increase the WACC.

It reduces the COE because the volatility of the returns to equity holders is lower at lower leverage levels.[[19]](#footnote-20) This tends to reduce the WACC.

It increases the COE because some of the default risk shifts to equity holders at lower leverage levels. [[20]](#footnote-21) This tends to increase the WACC.

We consider a range of alternative debt ratios for the No MOPR case, repeating steps 1 through 7 to determine the ATWACC for each debt ratio. This allows us to evaluate whether the total WACC in the No MOPR case could be reduced by lowering the amount of project debt. We estimate the final WACC parameters in the No MOPR case as the set of values (for COE, COD and debt ratio) that minimize the total ATWACC.

1. Conclusion

The WACC parameters developed as part of the recent CONE study, which relies on a review of historical financial market data, provide a proxy for the returns required by investors in merchant assets in ISO-NE markets with a MOPR. However, there are no available historic comparables for a competitive power market that motivates merchant new entry without a MOPR amid high levels of policy-driven investment. Hence, a different approach is needed to account for the effects of eliminating the MOPR provisions on the WACC.

Accordingly, we developed a model for estimating how future price volatility would be affected by a change in market rules (i.e., elimination of MOPR). Our model estimates how a change in price volatility resulting from MOPR elimination would change:

The cost of equity using the Capital Asset Pricing Model (“CAPM”); and

An investor’s cost of debt based on criteria employed by credit rating agencies.

We described the overall approach and each of the steps in our model in this section. Nonetheless, the approach we developed for our study may not be required in future CONE studies. This is because future studies may be able to utilize the methods used by previous studies if sufficient historical market data is available after the MOPR is eliminated.

1. Model Inputs

Our model considers a range of inputs that affect the volatility of revenues to the reference unit. In this section, we discuss the principles for determining the model inputs (subsection A), and the key inputs/ assumptions underlying our model (subsection B).

1. Principles for Determining Model Inputs

The model is designed to estimate how a change in market rules would lead to a change in the financial risk for investors relative to the status quo. Consequently, the only difference between the MOPR case and No MOPR case is that the former uses the current offer floor mitigation rules for subsidized resources while the latter does not. Hence, the differences in financial risk between the two cases in the model are directly attributable to MOPR elimination rather than other factors.

The input assumptions for the model were developed considering the following:

First, the model evaluates the capacity market under long-term equilibrium conditions where wholesale market revenues are *expected* to be just sufficient to recoup the cost of new entry to maintain the system at the 1 day in 10 years reliability standard. However, this does not guarantee revenues, since unforeseen factors cause revenues to be higher or lower than expected, making new supply investment risky.

Second, the factors driving financial risk in the model should reasonably characterize circumstances that will contribute to revenue volatility during the (~20-year) investment horizon of resources deciding whether to sell capacity in the next few FCAs. We anticipate high levels of policy-driven investment to decarbonize the grid affecting both supply-side and demand-side participation.

Third, it is important to avoid unnecessary complexity in any modeling exercise.

Given these considerations, we model the New England power system based on anticipated conditions around 2030. This timeframe has the advantage of being more clearly defined in New England State policy goals, allowing us to draw assumptions about potential policy pathways from State-sponsored publications. Conditions in 2030 are close enough to influence the near-term outlook of prospective investors, but it also serves as a proxy for market conditions that are likely to drive revenue volatility over the subsequent decade, which constitutes the medium and long-term view of investors.

To avoid unnecessary complexity, we model all of the new entry and retirement decisions leading up to 2030 in a single time step (rather than modeling decisions in each year leading up to 2030). The model estimates expected revenue volatility for a three-year rather than one-year period.[[21]](#footnote-22) This is reasonable because investors rarely make significant retirement or new entry decisions based on a single year of very low or high revenues. Furthermore, three years aligns with the duration of a potential downside case that a lender would consider when evaluating a potential investment.

Since the model estimates how a change in market rules would increase or decrease financial risk, assumptions about the initial cost of capital in the MOPR case are based on the CONE study. We do not attempt to reevaluate financial risk in the MOPR case.

The next subsection of this report discusses the specific assumptions about supply and demand used in the model and how they were made consistent with the principles discussed above. We rely primarily on publications of New England States with detailed information about clean energy policies as the region transitions from a conventional fleet to one with high penetration of clean resources. There is some uncertainty regarding the specific policy measures and the timing and quantities of future new supply investment.[[22]](#footnote-23) Hence, we model individual scenarios with probability weights that could affect the volatility of wholesale market revenues. Scenarios regarding state policies are derived primarily from key documents supporting legislation and/or regulations (e.g., the 2050 Decarbonization Roadmap). We also develop scenarios related to the competitive market responses of conventional new and existing resources and merchant battery storage resources.

1. Model Inputs

In this subsection, we discuss for each key model input, the relevance of the input, the values we assumed (and their sources) for our analysis.[[23]](#footnote-24) This subsection organizes model inputs into the following categories:

Capacity Demand

Capacity Supply

Reference Unit Revenues

Financial Parameters

* + 1. Capacity Demand

The primary driver of demand for capacity is the peak load forecast, which is affected by uncertainty in traditional gross load drivers (e.g., economic growth forecast), and other policy-driven factors such as adoption of energy efficiency, distributed resources, and the level of building and transportation electrification. Uncertainty in load forecast can have a significant impact on the expected outcomes, and hence, load forecast uncertainty is a key driver of uncertainty in revenues to merchant resources.

We modeled four peak load scenarios with equal probability weights in both MOPR and No MOPR cases. Our assumed scenarios are based on the ISO’s 2021 CELT forecast for 2030, and the following three cases from Massachusetts’ *Pathways to Deep Decarbonization Study*:

*All Options* – This scenario assumes that decarbonization targets are met using the most economic set of resources using baseline cost assumptions for all technological options.

*Limited Efficiency* – This scenario assumes fewer opportunities for energy efficiency when compared to the *All Options* scenario.

*DER Breakthrough* – This scenario assumed greater penetration of behind-the-meter solar PV and flexible loads relative to the *All Options* scenario.

The following figure shows the peak load forecast levels in the four scenarios we modeled.

Figure 8: Peak Load Forecast Scenarios



* + 1. Capacity Supply

Uncertainty regarding the quantity and cost of supply can also have a significant impact on the expected future outcomes. This part of the subsection describes our assumptions regarding the following categories of supply:

Existing Resources

Capacity Imports

Offshore Wind Generation

Energy Storage and Solar Resources

New Combustion Turbines

The assumptions for each category are described below.

Existing Resources

We included supply from various types of internal capacity resources based on the actual cleared quantities in FCA-15. In developing our assumptions for capacity supply offers, we grouped resources according to their fuel type and/or prime mover type, and we reviewed the class average net going forward costs (“Net GFCs”) from studies that have been conducted for NESCOE and NEPOOL.[[24]](#footnote-25) We also considered the performance of these resource types in shortage events during the 2018 event, and their likely performance during shortages in a system with high renewable penetration. Ultimately,

We assumed that the offers from most non-fossil resources will be low and in the range of $0 to $1/kW-month.[[25]](#footnote-26)

We assumed that offers from CCs and CTs will range from $1-$4/kW-mo with CCs that entered into service before 2000 having higher costs (due to their inflexible characteristics) relative to other CCs and CTs.

Oil/gas-fired steam turbines are assumed to offer to sell capacity at a breakeven level considering based on relatively high ($21/kw-month in 2030$) GFCs, higher expected future PPR levels, and their typically poor performance in PFP events.

These capacity offers were set considering the revenue levels that would result in retirements in sustained over a three-year period. Hence, these capacity offers are generally higher than what would be appropriate if we were modeling a single year of revenues.

Capacity Imports

We included capacity supply from the following neighboring markets:[[26]](#footnote-27)

*New York* – Consistent with recent FCA outcomes, we included up to 750 MW of imports from New York. We assumed that imports from New York are price sensitive, and that the offer levels depend on: (a) the slope of the demand curve in the New York Control Area (“NYCA”), and (b) the capacity prices in NYCA. We considered 3 scenarios (with equal probability weights) for the surplus/ capacity prices in NYCA:

* *Large Surplus* - NYCA prices are close to $0/kW-mo. An upward sloping import cost curve rises from $0 based on the slope of the NYCA capacity demand curve.
* *Moderate Surplus* - NYCA prices are half its Net CONE. The import cost curve rises from this level based on the slope of the NYCA capacity demand curve.
* *NYISO is at criteria* - NYCA prices at its Net CONE. The import cost curve starts at this level.

*Hydro Quebec and New Brunswick* – We included imports from Canada (HQ and New Brunswick) over existing as well as potential new transmission ties.

* + *Existing Ties* – We included imports from Canada over existing lines based on actual cleared quantities in FCA-15.
  + *New Transmission Lines* – The Massachusetts utilities have entered into long-term contracts with New England Clean Energy Connect (“NECEC”), which is a 1200 MW HVDC transmissions line. For the purposes of our analysis, we assigned a weight of 80 percent to the scenario where the NECEC is in-service.

New Offshore Wind Resources

Several New England states have set targets to procure offshore wind resources. However, the quantity and timing of entry is uncertain. The target quantities and the timing of the targets have become increasingly aggressive (see Table 1) over the years. Conversely, there have also been delays in entry of offshore wind resources that have already secured contracts with state utilities. We developed three equally weighted scenarios for offshore wind capacity in 2030: [[27]](#footnote-28)

*Mid* – Assumes offshore wind quantities that are currently targeted by 2030 by Massachusetts, Connecticut and Rhode Island.

*Low* – Includes only the procurements that are currently underway or complete.

*High* – Assumes additional procurements similar to recent increases in MA, CT and RI. These states have increased their targets by over 4 GW in the last 4 years (see Table 1).

We estimated the amount of capacity that could be sold in future FCAs using an ELCC curve that reflects the falling capacity value of offshore wind resources as the penetration levels increase.[[28]](#footnote-29) We further assumed that the offshore wind resources will offer into the FCA at the starting price in the MOPR case (consistent with the latest ORTP for offshore wind), and will be price takers in the No MOPR case.

New Energy Storage and Solar Resources

Investments in solar and energy storage (“ES”) resources are supported by a variety of state programs such as Renewable Portfolio Standards, storage-specific mandates, and Massachusetts’ SMART program and Clean Peak Standard programs. Like offshore wind programs, the state targets for these technologies have grown in recent years. However, the capacity supply from these resources at a given time depends on the technology costs, the pace of development, and the target quantities, which are all uncertain. Indeed, the amount of new utility-scale solar capacity in 2030 varies from less than 2 GW to over 6 GW across the scenarios studied in the Massachusetts’ Decarbonization Roadmap study.

We assumed the nameplate capacity in 2030 for solar and ES resources that are interdependent.[[29]](#footnote-30) Specifically, we use the following three solar-target scenarios:

*Mid* – In this scenario, the subsidized solar capacity is based on the SMART program target for 2030.

*Low* – The target for solar capacity in this scenario is based on the 2021 CELT report forecast of FCM-PV.

*High* – The target for solar capacity in this scenario is based on the deployment by 2030 in the ‘100 percent renewable primary’ case of the MA Pathways study.

We use the following three storage-target scenarios:

*Mid* – The capacity target for subsidized ES resources is based on existing storage-specific state targets, and the estimated capacity that will be supported through SMART and Clean Peak programs.

*Low* – Assumes a 50 percent shortfall in attaining ES Mid-target.

*High* – The total ES resources across all the states will be 150 MW storage per 1 GW of ISO-wide peak load.

Figure 9shows the target capacities (nameplate) for the three solar scenarios and the three ES resources scenarios.

Figure 9: Targets for Solar and Storage Resources (nameplate capacity)



Solar and ES resources can have greater capacity value (quantified using ELCC methods) in combination than individually. Hence, we considered synergies between ES and solar penetration in translating the target capacities into qualified capacity from these resources. We developed ELCC values for solar and storage resources in the above scenarios using data from several regional studies.[[30]](#footnote-31)

Figure 10 shows for each scenario, the total subsidized capacity from solar and ES resources that would be sold in the FCM.

Figure 10: Qualified Capacity from Subsidized Energy Storage and Solar Resources



For determining the solar target capacity in each Monte Carlo realization, we assumed equal weighting of the three solar scenarios described above. Our assumed probability weighting of the ES scenarios depends on the cost of the batteries, which we treat as a stochastic variable in our model. We assumed that the probability of higher ES quantity targets is inversely correlated to storage costs. Battery costs in 2030 are assumed to be a uniform distribution bounded by *Conservative* and *Advanced* cases published by NREL (see Figure 11). Ultimately, we assumed that:

If the battery costs are in the top third of the distribution (i.e., costs are high), the ES capacity target is equally weighted between low and medium scenarios.

If the battery costs are in the bottom third of the distribution (i.e., costs are low), the ES capacity target is equally weighted between high and medium scenarios.

If the battery costs are in the middle third of the distribution (i.e., costs are in the mid-range), the ES capacity target is equally weighted between low, medium and high scenarios.

Figure 11: NREL’s 4-hour Battery Cost Projections[[31]](#footnote-32)

Chart, line chart

Description automatically generated

Since Class I REC revenues are treated as “in-market” revenue for the purposes of Offer Floor Price calculation, we assume solar resources will be price-takers in both MOPR and No MOPR cases. We assume ES resources are price-takers in the No MOPR case, to the extent they are subsidized, with the possibility of additional merchant entry at higher prices according to the battery cost scenario described above. In the MOPR case, the offer price depends on the battery cost scenario with the average offer prices (before adjusting for ELCC) being:

For 2-hr units, $2.9/kW-mo in 2030$, which is equal to their ORTP.

For 4-hr units, $6.40/kW-mo in 2030$, which is a value developed by the IMM’s consultants for its FCA-16 new resource reviews.

New Combustion Turbines

We assumed that a new CT will continue to be the reference unit for the capacity demand curve. However, the ability of new fossil-fired resources to be permitted and the availability of sites for building a large number of new CTs is unclear. Hence, we modeled four equally weighted scenarios with varying quantities (2 to 8 CTs or approximately 740MW to 3GW) of feasible new CT build.

In each scenario, we assume that half the new CTs offer their capacity at Net CONE while the other half offer at a slightly higher price of Net CONE + $0.75/kW-mo.

* + 1. Reference Unit Revenues

The reference unit receives capacity revenues, revenues from sale of energy and ancillary services (“EAS”), and Pay for Performance (“PFP”) revenues. All these revenue streams tend to decline (at varying rates) as the capacity surplus increases. In this subsection, we describe our methodology for estimating the revenue to the reference unit as the various assumptions about supply and demand from the previous subsections combine to produce a Monte Carlo realization-specific capacity surplus.

Capacity Revenues

In each Monte Carlo realization, we determine the capacity revenues to the reference unit using the realization-specific capacity surplus and the capacity demand curve. We determine the demand curve by scaling the MRI curve used in FCA-15 using the iteration-specific Net CONE of the reference unit.

Energy and Ancillary Services Revenues

As part of the CONE study, the ISO’s consultants estimated the revenues a CT would earn from the sale of Energy and Ancillary Services (“EAS”) at criteria using the results of a production cost model and a simplified dispatch model.[[32]](#footnote-33) The consultants also estimated the unit’s EAS revenues under historical surplus conditions in its ORTP analysis. We utilized these revenue estimates to develop our model, which estimates EAS revenues of the Reference Unit in each Monte Carlo realization in the following manner:

EAS revenues are assumed to be a stochastic variable with a mean and standard deviation that decrease linearly as the capacity surplus increases (see Figure 12). We assumed that the revenues are distributed normally.

This linear relationship is consistent with using: (a) EAS revenues of a new CT at criteria from the CONE Study, and (b) EAS revenues used in the new CT’s ORTP which was estimated for a surplus of approximately 600MW (average over 2016/17-2018/19).

Figure 12 shows the assumed relationship between the EAS revenue offset and the capacity surplus. The revenues shown consider prices that do not include the effects of the Reserve Constraint Penalty Factor (“RCPF”) during shortage events, which are addressed along with PFP revenues in the next part of this subsection.

Figure 12: Distribution of EAS Revenues at Various Surplus Levels



As noted in IV.A, the revenue in each Monte Carlo realization in our study represents the average of three years of revenue. Accordingly, we estimate the EAS revenue in each Monte Carlo realization as the average of three random draws from the assumed probability distribution of annual EAS revenues for a given surplus level.

Pay for Performance and Reserve Shortage Revenues

In addition to the EAS revenues discussed in the previous section, the Reference Unit could receive the following streams of revenues during reserve shortage hours: (a) Pay for Performance (“PFP”) revenues, when it performs better than the average resource, and (b) additional energy and reserve revenues (i.e., shortage revenues) due to the portion of the LMP that corresponds to the RCPF. We estimated these revenues in each realization using the following parameters:

The number of reserve shortage hours (“H”) in the realization. The distribution of H depends on the capacity surplus.

* + Figure 13 shows the distribution of H as a function of the capacity surplus. We estimate the H in each realization using (a) the capacity surplus in the realization, and (b) the average of three random draws from the distribution for H at that level of surplus.
  + We assume that the relationship between H and the capacity surplus is consistent with the results of the ISO’s study on *Estimated Hours of System Operating Reserve Deficiencies* for FCA-15.[[33]](#footnote-34),[[34]](#footnote-35)

Figure 13: Estimated Hours of System Operating Reserve Deficiencies for 2024/25



The RCPF. Our assumed value for the RCPF ($1000/MWh) is consistent with the value used in the CONE study.

The performance of the unit during shortage events (“A”) and the average balancing ratio (“Br”). Our assumptions for A and Br are consistent with the values used in the CONE study.

The Performance Payment Rate (“PPR”). We utilized a PPR value that we developed by adjusting the PPR developed for FCA-16 by (a) inflating the PPR to 2030$, and (b) adjusting the resulting value using the ratio of H used in the CONE study and the mean H for FCA-15’s Capacity Commitment Period.[[35]](#footnote-36)

* + 1. Financial Inputs

The estimation of COE and COD relies a number of financial assumptions. These include CAPM parameters (CAPM betas, risk free rate, market risk premium), cost of debt and capital structure for merchant and regulated entities, bond yields by rating, tax rates, etc. To the extent applicable, we utilized data from the CONE study for many of these parameters. We have posted supplemental spreadsheets that detail the values that we used for these parameters and the sources for each of them.[[36]](#footnote-37)

1. Results and Conclusions

Using the modeling approach discussed in Section III and the inputs described in Section IV, we estimated how changes in the MOPR rules would be expected to affect financial risk for a merchant investor. This section provides an overview of the results of our analysis, including the estimated effects on the cost of capital used in setting the capacity demand curve. Subsection A provides detailed results.[[37]](#footnote-38) The overall conclusions of our analysis are provided in subsection B.

1. Results

In this subsection, we summarize various intermediate modeling results that demonstrate how we estimate the impact of MOPR elimination on the ATWACC and Net CONE of the reference unit. We discuss the following results from our analysis in the rest of this subsection:

Distribution of revenues under long-term equilibrium conditions in the MOPR and No MOPR cases *before* WACC adjustment

Initial estimates for COE and COD in the No MOPR case

Iterations to determine final COE and COD at the default leverage ratio

Optimal leverage ratio and estimated final WACC for the No MOPR case

Estimated Net CONE in the No MOPR case

* + 1. Distribution of revenues in the MOPR and No MOPR cases before WACC adjustment

Figure 14 shows the distribution of revenues to the reference unit across 2000 Monte Carlo realizations in the MOPR and No MOPR cases under long-term equilibrium conditions. The chart shows the percentage of the total realizations on the horizontal axis where the revenue was higher than the value shown on the vertical axis. The figure also shows (a) the standard deviation of the distribution in each case, (b) the portion of the distribution where the revenues correspond to a B+/BB- rating (i.e., DSCR is between 1.27 and 1.53) in the MOPR case (labeled as Rating Case range), (c) the Rating Case revenues for the No MOPR case, and (d) the Base Case (i.e., average) revenues in the MOPR and No MOPR cases.

As discussed in III.B, given the surplus supply in both MOPR and No MOPR cases, the average revenue does not equal the Gross CONE of the reference unit in both cases. Hence, to study the impact of MOPR elimination at long-term equilibrium, we adjusted the supply stack by removing capacity from higher-cost existing resource. The amount of existing capacity that we removed is approximately (a) 1,150 MW in the MOPR case, and (b) 4,200 MW in the No MOPR case. The following figure shows the distribution of revenues after these supply adjustments are made.[[38]](#footnote-39) The figure also shows the average revenue and the Rating Case revenues (along with the Rating Case range) for each case.

Figure 14: Distribution of Revenues to Reference Unit with and without MOPR

Before Adjusting WACC Parameters (under Long-term Equilibrium Conditions)



Several observations can be drawn from the above figure:

Consistent with the long-term equilibrium conditions, the average revenue in both the MOPR and No MOPR cases equals the Gross CONE.

The distribution of revenues in the MOPR case is flatter than the revenue distribution in the No MOPR case, i.e., the standard deviation of the revenues in the No MOPR case is (by 56 percent) higher than that in the MOPR case.

The likelihood of low revenues (i.e., higher probability of downside scenarios) is higher in the No MOPR case. In specific, the average revenue in the Rating Case range in the No MOPR case is 17 percent lower than in the MOPR case. The Rating Case range, i.e., the portion of the distribution corresponding to a B+/BB- rating under status quo, falls between the 9th to 16th percentile of the revenue distribution.[[39]](#footnote-40)

The above characteristics of the revenue distribution affect the COE and COD in the No MOPR case, which we discuss in the next subsection.

* + 1. Initial Estimates of Cost of Equity and Cost of Debt

Cost of Equity

Based on the results shown in Figure 14, the higher standard deviation of revenues in the No MOPR case ($3.52/kW-month in 2030$) correspond to a higher COE relative to the MOPR case ($2.25/kW-month in 2030$). We estimate the increase in COE in the No MOPR case in the following manner:[[40]](#footnote-41), [[41]](#footnote-42)

*Increase in COE without MOPR = Std Dev(RevMOPR)/ Std Dev(RevNoMOPR) x Power Market Risk component of COE = 1.69%*

Given the 13 percent COE assumed for the MOPR case, our initial estimate of the COE in the No MOPR case is 14.69 percent.

Cost of Debt

The average revenue in the Rating Case range, i.e., the 9th and 16th percentile of the revenue distribution, in the MOPR case is $11.27/kW-mo (2030$).[[42]](#footnote-43) The average revenue in the same portion of distribution in the No MOPR case is 17 percent lower, which corresponds to a DSCR of 0.85. Consequently, we estimate an initial COD of 10.22 percent in the MOPR case, based on our assumed relationship between Rating Case DSCRs and the COD.[[43]](#footnote-44)

Table 4 shows the derivation of the DSCRs in the base case (i.e., the case with expected revenues), the Rating Case DSCRs in the MOPR and No MOPR cases.

Table 4: DSCRs in Base and Rating Case



* + 1. Iterations to determine COE and COD at the default debt ratio

The above estimates for COE and COD produces an initial ATWACC of 10.72 percent (assuming the default 55% debt ratio used in the CONE study). However, the distribution of revenues shown in Figure 14 is based on a capacity demand curve which utilizes a Net CONE that is based on 8.26 percent ATWACC. Similarly, the offers from new CTs and merchant energy storage are also based on an ATWACC of 8.26 percent. This highlights an inconsistency between:

(a) the COE and COD values that we assumed to estimate the revenue distribution in the No MOPR case, and

(b) the COE and COD values that are implied by the revenue distribution in the No MOPR case.

As discussed in III.B.3, we address this inconsistency through iterations in which we gradually changing the assumed COE and COD values such that the difference between (a) and (b) above is reduced. Figure 15 shows the results of these iterations for the debt ratio of 55%. The results indicate that the assumed and implied values of COE and COD converge reasonably well after 10 iterations. Ultimately, we estimate final COE and COD values at a debt ratio of 55 percent as 15.88 percent and 10.56 percent.

Figure 15: Iterations to determine COE and COD in No MOPR Case

At 55 percent debt ratio



* + 1. Estimated Optimal Leverage Ratio and Final ATWACC

As discussed in III.B, we evaluate whether the overall ATWACC can be lowered by adjusting the debt ratio in the No MOPR case. Figure 16 shows the results of this evaluation. For each level of assumed debt ratio, the figure shows the estimated ATWACC in the No MOPR case.

Figure 16: Change in ATWACC with Leverage



Our analysis indicates that the optimal debt ratio in the No MOPR case is approximately 40 percent. At this debt ratio:

The COD in the No MOPR case is reduced to 5.12 percent (compared to the COD at a 55 percent debt ratio). This is because the Rating Case DSCR improved from 0.82 at a 55 percent debt ratio to 1.59 at a 40 percent debt ratio.

The COE in the No MOPR case also declines to 15.03 percent. This is because the volatility of returns to equity holders is lower at a 40 percent debt ratio relative to the volatility at a 55 percent debt ratio.[[44]](#footnote-45)

Overall, we estimate the ATWACC in the No MOPR case to be 10.51 percent. This estimate considers the effects of a lower (40 percent) debt ratio, including the resulting decrease in the COE and COD (which reduce the ATWACC) and the associated increase in the weight of the COE (which increases the ATWACC).

The higher final ATWACC in the No MOPR case affects the capacity supply and demand curves, which affects the distribution of revenues to the reference unit. The following figure shows the distribution of revenues to the reference unit for the following cases: (a) MOPR case, (b) No MOPR case before WACC adjustment, and (c) No MOPR case after WACC adjustment. The Figure also shows the risk metrics of interest (standard deviations and Rating Case revenues) for estimating the COE and COD.

Figure 17: Distribution of Revenues to Reference Unit

MOPR Case, and No MOPR case before and after WACC Adjustment



As shown in the above figure, the revenue in the No MOPR case even after the WACC adjustment is still more volatile (i.e., has a higher standard deviation) than in the MOPR case, and there continues to be a higher downside risk to the merchant reference unit. Nonetheless, the average revenue in the No MOPR case after WACC adjustment is 11 percent higher than in the MOPR case.

* + 1. Estimating Net CONE and PPR in the No MOPR Case

We estimated the Net CONE in the No MOPR case by incorporating the above WACC parameters into the ISO’s discounted cash flow model. We determined that if MOPR is eliminated, the Net CONE needs be increased to $8.66/kW-mo in 2025$ which is 16 percent higher than the Net CONE of $7.47/kW-mo under status quo.

Updating the WACC parameters to calculate the Net CONE would also involve developing a new estimate for the PPR. This is because the ISO sets the PPR such that if the reference unit’s performance is zero during shortage hours, its PFP penalties would fully offset its capacity revenues.[[45]](#footnote-46) Hence, the PPR is a function of the Net CONE and should increase as the Net CONE increases. Accordingly, we updated the PPR to $10,846/MWh (compared to $9,337/MWh under status quo) to reflect the higher Net CONE in the No MOPR case.[[46]](#footnote-47)

1. Conclusions

We developed a model that evaluated the impact of eliminating MOPR on the financial risk to investors. We find that:

There is a considerable difference in the volatility of revenues to the reference unit with and without MOPR.

The ATWACC without MOPR should be increased to 10.51 percent (from 8.26 percent under status quo) to compensate investors for the higher risk in the No MOPR case.

This increase in ATWACC translates into a Net CONE of $8.66/kW-month (or 16 percent higher than the current value of $7.47/kW-month in 2025$). In addition, the PPR should be increased to $10,846/MWh from $9,337/MWh, to reflect the higher Net CONE of the reference unit.

1. The functions of the External Market Monitor are listed in Appendix III.A.2.2 of “Market Rule 1.” [↑](#footnote-ref-2)
2. Under long-term equilibrium conditions, the total revenues to the reference unit are adequate to cover its capital and operating expenses. [↑](#footnote-ref-3)
3. See Table 1 for the extent to which the states’ procurement targets for certain key technologies have evolved in recent years. [↑](#footnote-ref-4)
4. See *Section 4: Financial Assumptions* of the December 2020 report *ISO-NE CONE and ORTP Analysis*. [↑](#footnote-ref-5)
5. Under the CAPM formulation,

   *Expected return of equity for an asset a = Risk-free Rate + βa x Market Risk Premium*

   The CAPM βa estimated as: *βa = σa/σm x ρa,m* where,

   *βa* is the asset beta,

   *σa* is the standard deviation of the asset’s returns,

   *σm* is the standard deviation of the market’s returns,

   *ρa,m* is the correlation coefficient of market’s returns to the asset’s returns.

   Therefore, if the standard deviation of the asset’s returns increase, the beta of the asset will increase linearly, since the correlation coefficient of the asset’s returns and the market’s returns are expected to remain constant. [↑](#footnote-ref-6)
6. For instance, the project development risk, risk of fuel supply disruptions, and performance risk are unlikely to be different across the MOPR and No MOPR cases. [↑](#footnote-ref-7)
7. For instance, Standard & Poor’s criteria for assessing operating risk considers the performance of the project under market trough conditions and the difference between the expected and trough market conditions. See pp. 44-48 and pp. 67-74 of Standard &Poor’s *Project Finance: Project Finance Operations Methodology* published on September 16, 2014. [↑](#footnote-ref-8)
8. While rating agencies consider various qualitative and quantitative criteria, the DSCR is a key metric that is utilized by all three rating agencies in evaluating loans. Fitch Ratings and S&P publish explicit guidance that maps a project’s DSCR to a debt rating. DSCRs can quantify the volatility in revenues over a portion of the term of a loan rather than the entire term, making them well-suited to our approach of modeling conditions over several years that are representative of long-term equilibrium conditions. This differs from other metrics used by ratings agencies which measure the project’s ability to service its debt in aggregate over the loan term. [↑](#footnote-ref-9)
9. In addition to considering cash flows stresses due to market price volatility, the Rating Case also includes other stresses associated with higher operating costs, worse than expected performance, and higher rate of outages. See Fitch Ratings’ guidance for development of Rating Case on pages 9-10 of its *Thermal Power Project Rating Criteria* published in June 2021. [↑](#footnote-ref-10)
10. The table shows the guidance for a fully amortizing loan structure, which is similar to the treatment of debt in the model used to determine the Net CONE. However, most project finance-based merchant projects rely on a Term B Loans (“TLB”) structure for their debt. TLBs are characterized by a modest paydown of principal during the loan term (typically 5-7 years) and a large bullet payment at the end of the term. The bullet payments at the end of the term are usually refinanced using another TLB or paid down through a fully amortizing loan, depending on the remaining life of the project.

    The rating of a project that relies on TLB debt could be determined by the credit metrics in the TLB phase or in the refinance phase. As with a fully amortizing loan, DSCRs are a useful metric to evaluate a project in its TLB phase. If the DSCRs are robust in the TLB phase, the project’s rating may be determined by its evaluation in the refinance phase. Other metrics such as Project Life Coverage Ratio, Debt/ EBIDTA, CFADS/ Debt that help identify issues with the size of the leverage are typically used to evaluate the refinance phase of the project. However, unless the market environment is assumed to improve with time, high levels of leverage at the end of the TLB phase are likely to translate into low annual DSCRs in the refinance phase. Hence, for our analysis which looks at a time period shorter than the full term of typical TLB debt, the DSCR-based guidance for fully amortizing loans provides a reasonable basis for estimating how changes in volatility would affect the project’s debt rating. [↑](#footnote-ref-11)
11. See table on *Indicative Rating Cases — Thermal Projects* on page 10 of Fitch Ratings’ *Thermal Power Project Rating Criteria* published in June 2021. See *Table 4 - Market Exposure: Market Downside Case Guidance For Power Projects* and *Table 8 - Power Projects: Standard & Poor's Downside Case Assumptions Guidance*, Standard & Poor’s *Project Finance: Key Credit Factors For Power Project Financings* published on September 16, 2014. [↑](#footnote-ref-12)
12. See *Financial Assumptions.xlsx* file in the *Inputs* folder for data on bond yields. [↑](#footnote-ref-13)
13. See *Financial Assumptions.xlsx* file in the Inputs folder for data on bond yields. [↑](#footnote-ref-14)
14. Given our assumptions about the capacity supply offers from existing units, the revenue in each Monte Carlo realization should be interpreted as the average over three years. [↑](#footnote-ref-15)
15. See section IV for a discussion of the values assumed for each of these variables. [↑](#footnote-ref-16)
16. We assume the COE and COD in the MOPR case to equal the values developed in the most recent CONE study. [↑](#footnote-ref-17)
17. We estimate the power market risk component to be 300 basis points. See *Financial Assumptions.xlsx* file in the *Inputs* folder for the inputs and calculations underlying the assumed power market risk component. [↑](#footnote-ref-18)
18. In determining the COD at various leverage levels, we constrain the rating in the No MOPR case to BB. This is consistent with the guidance from S&P and Fitch Ratings which cap the debt rating in the B+ to BB+ range because of (a) limited historical data, and (b) high market uncertainty and larger difference between the expected and downside conditions. See discussion on page 11 of Fitch Ratings’ *Thermal Power Project Rating Criteria* published in June 2021. See pp. 85-95 of Standard &Poor’s *Project Finance: Project Finance Operations Methodology* published on September 16, 2014. [↑](#footnote-ref-19)
19. We utilize the extended Hamada equation (or the Conine equation) to characterize this relationship.

    *βL = βU x (1 + (1-T) \* (D/E)) - βD x (1-T) x (D/E)*

    Where:

    *βL* – levered equity β

    *βU* – unlevered equity β

    *βD* – β of debt

    *T* – tax rate

    *D/E* – debt-to-equity ratio [↑](#footnote-ref-20)
20. *Id.* [↑](#footnote-ref-21)
21. While the term “volatility” is colloquially used to describe the up-and-down movement in prices, throughout this report, we use the term as it is defined in financial market theory as a measure of the uncertainty faced by financial market participants. [↑](#footnote-ref-22)
22. For instance, some policies allow flexibility regarding the target technology (e.g., whether the policy will focus on solar or wind to achieve certain targets). Furthermore, some states have made slower than expected progress toward stated policy goals (e.g., a project originally contracted with a utility to enter in 2024 might not enter the market until 2026). [↑](#footnote-ref-23)
23. In addition to the discussion in this section, we posted a folder (labeled *Inputs*) with files containing various inputs to the model. [↑](#footnote-ref-24)
24. See *Offers Summary.xlsx* file in the *Inputs* folder for our assumptions regarding offers from existing resources. [↑](#footnote-ref-25)
25. Unless noted otherwise, all offers, prices and revenues in this section are shown in 2030$. [↑](#footnote-ref-26)
26. See *Offers Summary.xlsx* file in the *Inputs* folder for our assumptions regarding capacity supply offers from neighboring control areas. [↑](#footnote-ref-27)
27. See *OSW Solar and ES MW Summary.xlsx* file in the *Inputs* folder for our assumptions (and their data sources) regarding offshore wind capacity (nameplate and qualified) in each scenario. [↑](#footnote-ref-28)
28. The curve we relied on was developed for the New York system, but it considered comparable quantities of intermittent resources. See The Brattle Group’s 2020 [presentation](https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B9D20EBBD-4DF8-4E4E-BEC1-F4452345EBFA%7D) on Quantitative Analysis of Resource Adequacy Structures. [↑](#footnote-ref-29)
29. See *OSW Solar and ES MW Summary.xlsx* file in the *Inputs* folder for our assumptions (and their data sources) regarding solar and energy storage resources capacity (nameplate and qualified) in each scenario. [↑](#footnote-ref-30)
30. The ELCC curve for solar resources was derived from a 2020 Brattle Group study of the New York system. See The Brattle Group’s 2020 [presentation](https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B9D20EBBD-4DF8-4E4E-BEC1-F4452345EBFA%7D) on *Quantitative Analysis of Resource Adequacy Structures*.

    The ELCC of ES resources was adjusted to account for renewable resource penetration based on a 2019 study by NREL for ISO-NE. See NREL’s 2019 [report](https://www.nrel.gov/docs/fy19osti/74184.pdf) on *The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States.*

    The slope of ELCC curves for 2-hour and 4-hour storage resources were derived from a 2019 study by GE for the New York system. See GE Energy Consulting’s 2019 [presentation](https://www.nyiso.com/documents/20142/4358080/01082019%20Capacity%20Value%20of%20Resources%20with%20Energy%20Limitations_v2.pdf/3499da16-12d8-16b7-b12f-be7650e64b63) on Valuing Capacity for Resources with Energy Limitations [↑](#footnote-ref-31)
31. See NREL’s 2019 [report](https://www.nrel.gov/docs/fy19osti/74184.pdf) on *The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States.* [↑](#footnote-ref-32)
32. The revenue offset discussed in this subsection excludes EAS revenues during shortage events. [↑](#footnote-ref-33)
33. The mean H used for our analysis differs from the value used in the CONE study. While the CONE study uses the average H (11.3 hours) from the Capacity Commitment Periods for FCAs 11-15, we use the mean (summer) H (7.9 hours) from the study for only FCA-15. Our choice was driven by the availability of data characterizing the relationship between H and the capacity surplus level. Assuming a higher mean H that is closer to the H from the CONE study would not affect the average PFP revenues, since the PPR value would be lower. Hence, the contribution of PFP revenues to the Net CONE of the reference unit is likely to be similar between the CONE study and our analysis. [↑](#footnote-ref-34)
34. We assumed that existing capacity would be retained, if necessary, to satisfy a reliability standard of 1-day-in-5-year LOLE. As a result, the shortfall in capacity (relative to the ICR) is limited to approximately negative 610 MW. This assumption bounds the H value, but it does not affect the capacity prices because the maximum price for the FCA is consistent with the capacity surplus level at which the LOLE is 1-day-in-5-years. [↑](#footnote-ref-35)
35. The ISO determines the PPR as a function of the Gross CONE of the reference unit. We hold the PPR constant when determining the WACC in the No MOPR case and, modify the PPR in the No MOPR case after finalizing the WACC parameters. [↑](#footnote-ref-36)
36. See *Financial Assumptions.xlsx* file in the *Inputs* folder. [↑](#footnote-ref-37)
37. In addition to the results discussed in this report, we posted files containing detailed model results. These include realization-level data on supply and demand variables, clearing prices, total revenues and various other tables that summarize/ aggregate these data. See *Outputs* folder. [↑](#footnote-ref-38)
38. The capacity that we removed was mostly from inflexible combined cycle units. We assumed that combined cycle units installed before 2000 will have higher offers than other combined cycle units. This is because these units are among the existing fleet’s least flexible units and are likely to incur substantial PFP penalties given their likely worse-than-average availability, particularly in a high renewable penetration scenario. For the purpose of our analysis, we assumed that all steam turbines are retired or no longer sell capacity due to high GFCs, higher PPR, and poor performance in PFP events. See *Offers Summary.xlsx* file in the *Inputs* folder for our assumptions regarding offers from existing resources. [↑](#footnote-ref-39)
39. See IIIA.B.2 for discussion of methodology for estimating COD. [↑](#footnote-ref-40)
40. See discussion in III.B.1. [↑](#footnote-ref-41)
41. Unless noted otherwise, all prices and revenues in this section are shown in 2030$. [↑](#footnote-ref-42)
42. The B+/BB- rating under status quo, i.e., the Rating Case range, corresponds to the 9th to 16th percentile of the revenue distribution. See IIIA.B.2 for discussion of methodology for estimating COD. [↑](#footnote-ref-43)
43. See Figure 6. [↑](#footnote-ref-44)
44. In general, Return to equity = (Free Cash Flow – Debt payment)/ Equity Value. Hence, as the equity value decreases (i.e., the denominator decreases), all else being equal, the volatility of the returns to equity holders increases. This increase in volatility at higher leverage levels is partially offset by the reduction in COE as some of the default risk shifts away from equity holders (to debt holders). [↑](#footnote-ref-45)
45. This condition is characterized by the following relationship: PPR = (Gross CONE – EAS revenue) / (H x A). See ISO’s September 2013 [memo](https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep10112013/a12a_iso_memo_09_04_13.pdf) on *FCM Performance Incentives – Performance Payment Rate*. [↑](#footnote-ref-46)
46. Although the estimated final PPR in the No MOPR case is higher, we use the same PPR value for both MOPR and No MOPR cases in determining the impact of MOPR elimination on WACC. This simplification is unlikely to have a significant impact on the final estimate for Net CONE in the No MOPR case. [↑](#footnote-ref-47)