NEPOOL 2016 IMAPP Proposals

Observations, Issues, and Next Steps

ISO Discussion Paper
January 2017

At the Integrating Markets and Public Policy (IMAPP) meeting on November 10, 2016, stakeholders requested that the ISO provide feedback on proposals presented during the IMAPP sessions in 2016. This memorandum shares the ISO's observations and highlights key issues regarding these proposals.

For discussion purposes, this memorandum groups the IMAPP proposals into three categories: Carbon pricing in the energy markets, forward clean energy markets (whether conducted separately from, or jointly with, the Forward Capacity Auction (FCA)), and 'two-tiered' pricing reforms to the Forward Capacity Market (FCM). The first two categories propose new ISO-administered mechanisms that seek to monetize carbon-free energy production to help achieve states' policy objectives. The last category does not aim to reduce carbon emissions directly, but instead seeks to ameliorate the potential suppression of FCM prices due to state-subsidized renewables while accommodating their entry into the capacity market. We emphasize that these proposals are not mutually exclusive, as many stakeholders have noted.

The ISO appreciates the discussions and conceptual design efforts that have been led by stakeholders throughout the IMAPP process. Importantly, in this memorandum the ISO is not taking a position supporting (or not supporting) the detailed development of any particular proposal by stakeholders. Rather, this memo serves to highlight key aspects or practical concerns with ideas discussed in the IMAPP process to date, in the interest of furthering understanding and discussion of the proposals' implications.[1] We look forward to discussing these observations with NEPOOL at its January 25th meeting.

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[1] This reflects the ISO's interpretation and understanding of stakeholders' IMAPP proposals presented during 2016. The ISO welcomes any corrections, and notes that if stakeholders' proposals are revised going forward, these observations may no longer apply.

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Carbon Pricing

Under a carbon pricing system, each electricity producer would pay an emissions fee in direct proportion to the amount of carbon (in tons) its generation facilities emit. The carbon emissions price (that is, the fee per ton emitted) could be fixed, be a set price schedule that increases over time, or be dynamically adjusted based on aggregate performance over time to satisfy specific carbon reduction objectives. This general design has been discussed during the IMAPP process by numerous market participants including the Conservation Law Foundation (CLF), Synapse Energy Economics, and Exelon.

In its simplest ISO-administered form, the ISO would charge emitting generators for their actual carbon emissions in the ISO's energy market settlement system. Each individual generator would then incorporate this cost into its energy supply offer, which will alter the region's generation supply stack to make non-emitting generation more likely to be economic. The emissions fees that are collected are returned to consumers or to wholesale buyers under a rebate allocation system (*see* more below).

Summary Observations

Carbon pricing creates simple, transparent incentives for reducing carbon emissions for both energy consumers and energy producers. Like many other market-based air emissions programs (such as the nitrogen oxides (NOx) emissions reduction program administered by the US Environmental Protection Agency (EPA)), carbon pricing is expressly intended to find the most cost-effective way for the economy to achieve carbon reduction objectives.[2] Unlike other carbon reduction approaches, however, carbon pricing does not mandate specific carbon abatement methods, nor pick the innovations, investments, or technology types that should be used to reduce emissions.

As with some other approaches (such as a forward clean energy market), the principal effect of carbon pricing on the supply side of the market would be to spur new (and to maintain existing) investment in low-to-non-emitting generation facilities. Emitting facilities become less profitable to build and maintain, while non-emitting facilities become more profitable and competitive. In contrast to forward clean energy markets, however, carbon pricing also sends a demand-side signal to reduce energy use when high carbon-emitting resources are operating. This will likely spur greater energy-efficiency investments, by making them more cost-effective.

Pricing air emissions directly is sometimes mischaracterized as "pay and pray" environmental policy.[3] As some participants have noted during the IMAPP process, by using a fixed carbon price, the

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[2] The literature studying modern emissions markets, including both successes and lessons learned, is extensive. See, e.g., Jody Freeman and Charles D. Kolstad, *Moving to Markets in Environmental Regulation: Lessons from Thirty Years of Experience* (Oxford University Press, 2006), and references therein.

[3] Some of New England's well-known thinkers in this area similarly dismiss this concern; *see* Massachusetts Institute of Technology President L. Rafael Reif's carbon pricing initiative ("[P]utting a price on carbon is one of the surest mechanisms available to accelerate the transition to low- and zero-carbon energy sources. Indeed,

impact on total emissions will not be known with complete certainty in advance – and may not "guarantee" specific carbon reduction targets each year. This is commonly addressed by adjusting the carbon price based on actual progress observed over time. Alternatively, it is possible to ensure a specific carbon emissions target is achieved by fixing the allowed annual power sector emissions level and permitting suppliers to trade emissions allowances at market-determined prices. The latter approach was taken in the widely-successful US sulfur dioxide (SO_2) emissions market that curbed acid rain, and is the approach of the Regional Greenhouse Gas Initiative (RGGI).

Ultimately, the principal benefit of carbon pricing, indicated by both theory and experience, is the dramatic reduction in cost of achieving air emission targets relative to expectations, and relative to technology-directed policy approaches.[4] This occurs because suppliers pursue the most cost-effective technologies.[5] In addition, these approaches produce cash revenue from the fees imposed on emitters that serves to lower its overall cost. We elaborate on this feature presently.

Practical Issues and Concerns

Although there are many implementation details, the fundamental idea of carbon pricing is straight-forward. Here, we emphasize three important practical considerations associated with any ISO-based approach to carbon pricing in New England.

Carbon Price Adjustments and Governance. To implement, an initial carbon price (or the allowance quantity) must be developed, as well as a governance process for how these would be adjusted over time. A possible starting point suggested in the IMAPP process is the US government's estimated social cost of carbon (approximately $42/short ton in 2020).[6] Alternately, the carbon price could be set dynamically based on economic conditions, overall energy prices, long-term emissions targets, or other factors to minimize its potential impact on costs while achieving abatement progress.[7] While any number of methodologies could be used to set carbon prices or allowance levels, these rules

over the last couple of years, as MIT [discussed] solutions to the climate challenge, supporting carbon pricing emerged as a clear point of consensus.") See http://news.mit.edu/2016/mit-joins-carbon-pricing-leadership-coalition-world-bank-imf-0520.

[4] This effect was vividly demonstrated in the early years of the SO_2 air emissions program. While the EPA projected abatement costs (and therefore allowance prices) in the range of $250 to $350 per ton of SO_2 emitted, actual abatement costs during the first three years of the program (1995-1997) were far less and auction prices tended to range from $100 to $150, reaching a low of $63. As a result, the impact of SO_2 pricing on electricity production costs was far less than policymakers' initial expectations. See P. L. Joskow, R. Schmalensee, and E. Bailey, 'The Market for Sulfur Dioxide Emissions', *American Economic Review*, 1998.

[5] See S. Rausch and V. J. Karplus, 'Markets versus Regulation: The Efficiency and Distributional Impacts of U.S. Climate Policy Proposals,' *Energy Journal* (2014, vol. 35), http://dx.doi.org/10.5547/01956574.35.SI1.11.

[6] See https://www.epa.gov/climatechange/social-cost-carbon. New York's Zero Emissions Credit (ZEC) program also uses this benchmark; see https://www.governor.ny.gov/news/governor-cuomo-announces-establishment-clean-energy-standard-mandates-50-percent-renewables.

[7] This option has been noted during the IMAPP process; see, for example, the Exelon August 11th presentation at http://nepool.com/uploads/IMAPP_Presentaion_exelon.pdf (*note typo in original link*).

and the associated governance process must be transparent to promote investment and carbon-reducing activities.

Rebate Allocation. The fees collected from generators for carbon emissions (or from auctioning emissions allowances, if applicable) must be distributed in some manner. In the design of emissions markets, this is sometimes called the "revenue recycling rule". There are many ways to recycle this revenue: as a rebate to energy consumers (via wholesale buyers), toward investment in energy efficiency programs, or some other agreed-upon mechanism. When determining how to redistribute this revenue, it is prudent to consider its other effects on electricity producers and consumers. For example, a carbon price is likely to reduce the cost of other state emissions-reduction programs (including the cost of state-subsidized energy-market contracts), lower total energy consumption, reduce the potential for pre-mature retirements of low-carbon generators (e.g., nuclear units), and may lower capacity prices (due to higher energy market revenues). Quantifying each of these effects, and determining appropriate rebate rules, would require further analysis.

Jurisdictional Questions. Finally, carbon pricing presents open jurisdictional questions under the Federal Power Act that have been discussed during the IMAPP process. When implemented as an allowance market administered by a state (or a state-regulated entity), the design appears broadly consistent with existing state and regional markets that have been approved by the courts such as RGGI and state Renewable Energy Certificate (REC) markets. However, if it was instead implemented and administered directly by the ISO under its FERC-approved Tariff, it presents new jurisdictional issues and may face greater legal scrutiny.[8]

Forward Clean Energy Market

In a Forward Clean Energy Market (FCEM), the ISO would administer forward energy contracts with qualified (no-or-low-carbon emitting) generation resources. The forward energy contracts would be solicited by auction, to be conducted (depending on the proposal) either jointly with, or shortly before, the annual FCA.

The primary objective of a FCEM is to facilitate the development of new, non-emitting generation resources, by providing multi-year forward financial contracts (or their equivalent via the ISO Tariff) that increase the new resources' expected revenues and decrease their investors' risk. This makes it easier to obtain project financing, lowers the cost of capital, and increases the total supply of renewable resources over time. A greater supply of renewable resources in the system tends to lower aggregate carbon emissions, as the relatively low operating costs of many non-emitting resources (e.g., hydro, solar, and wind) displaces energy production from higher operating-cost, emitting resources in the region's generation supply stack. Various approaches to a FCEM have been offered

[8] For a review of the jurisdictional issues, see J. Eisen, 'FERC's Expansive Authority to Transform the Electric Grid' at https://lawreview.law.ucdavis.edu/issues/49/5/Articles/49-5_Eisen.pdf, S. Weissman and R. Webb, 'Addressing Climate Change Without Legislation' at https://www.law.berkeley.edu/files/ccelp/FERC_Report_FINAL.pdf, and NEPOOL Counsel's October 21st presentation at http://nepool.com/uploads/IMAPP_20161021_Legal_Jurisdictional_Issues.pdf.

in the IMAPP process by market participants, and a general framework is summarized in a document presented at the September 14th IMAPP meeting.[9]

Summary Observations

A FCEM builds on the framework used to facilitate the entry of new renewable energy resources through long-term power purchase agreements and RECs, which utilities use to comply with state renewable portfolio standards. Because a FCEM subsidizes certain preferred carbon-abatement technologies, but not other carbon-reduction activities, it is not likely to be as cost-effective in reducing emissions as carbon pricing.[10] Nonetheless, the two approaches are not mutually exclusive, as many stakeholders have noted.

Because a FCEM structure contemplates creating an entire new product, auction process, and contract administration system, there are considerably more open questions associated with the FCEM concept than with the other major design categories discussed at IMAPP meetings. Indeed, from a market design perspective, many of the most important issues with a FCEM have received relatively little attention in the IMAPP process to date. For example, the underlying financial contract structure awarded in a FCEM affects risk for investors, how difficult it may be for developers to price FCEM bids properly at auction, and even the FCEM's effect on real-time energy markets and ISO operations. These are core issues, not peripheral matters: they can greatly affect the ability of a FCEM to achieve its primary objective – *viz*., to facilitate entry and lower financing costs – as well as whether it may have unintended consequences on energy market operational issues.

For those reasons, we devote more focus to several FCEM issues below than we allocate to the other major design categories discussed elsewhere in this memorandum (that is, carbon pricing and two-tier FCM pricing). This is not an indication of priorities or preferences on the ISO's part, but rather reflects that there are more outstanding, instrumental open issues to be developed and understood for a FCEM than with the other major proposal areas.

In addition, and in part for those very reasons, the ISO cautions that developing and implementing a wholly new ISO-administered FCEM product, auction process, and settlement administration system would be a lengthy, multi-year endeavor under the best of circumstances.

Practical Issues and Concerns

We address below four issues and concerns. The issues discussed are central concepts on which a successful forward energy contract market hangs together (or not), and whether it may have adverse consequences on other markets.

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[9] Available at http://nepool.com/uploads/IMAPP_20160914_Framework_FCEM.pdf.

[10] See S. Rausch and V. J. Karplus (link at note 5).

Issue 1: FCEM Contract Type and Structure

The most important consideration of any long-term forward market is the contract structure. Any FCEM is effectively awarding a financial instrument: the terms specify when and how much clean energy suppliers are paid, and when they are not. Consequently, the contract determines the allocation of risk borne by new resource investors versus consumers – and, therefore, the cost of new investment. In addition, the contract type determines what suppliers' offer prices actually represent in an auction.

There are many possible ways to design a forward contract for clean energy. Some of the possibilities presented in the IMAPP process are familiar within the energy project finance industry, and some are not. For concreteness, we specify four of these conceptual designs in Table 1 below, and explain their elements and differences subsequently. Please note these are ordered in Table 1 for expositional purposes, and do not reflect a ranking of their relative merits.

Table 1. A Taxonomy of FCEM Contract Type Alternatives

Contract Type	Common in Energy Project Finance	Contract and/or Offer Elements	Supplier's Bidding Complexity	Supplier's Risk	RT Energy Market Pricing Distortions
Contract for Differences	Yes	Strike Price (k), Contract Quantity (q)	Medium	Low	High (offer at RTM price floor)
Energy "Put" (Minimum Price Guarantee)	Yes	Strike Price (k), Contract Price (v), Contract Quantity (q)	High	Medium	High (offer at RTM price floor)
Fixed Price Adder	No	Price Adder (k), Contract Price (v), Contract Quantity (q)	Low	High	Medium (offer at marginal cost minus k)
Minimum Delivery Obligation with Shortfall Penalty	No	Contract Price (v), Minimum Quantity (q)	(Unclear)	High	Low (may offer at marginal cost less shortfall penalty)

Contract for Differences ("CfD"). A CfD is a standard financial instrument that typically includes two parameters. The *strike* price (conventionally abbreviated as *k*)[11] is equal to the fixed price the buyer pays for each MWh of energy delivered under the contract. The contract quantity (which we'll abbreviate as *q*) represents the total quantity of MWh the seller is awarded in the contract auction. We note these two contract elements in the third column in Table 1.

Offer Elements. With a CfD auction, the "price" in a FCEM supply offer is a resource-specific strike price, representing the minimum the supplier is willing to accept to provide its offered quantity of energy for the duration of the contract. In a uniform clearing price FCEM auction, the clearing price is then set by the offered strike price of the auction's marginal resource (or the demand curve, if applicable). From a market design standpoint, it is important for FCEM proposals to specify the contract type prior to how a FCEM auction would work, what the auction price represents, and so forth.

Supplier's Risk. A CfD is attractive and common in project finance because it provides the seller with price certainty in the energy market so its revenue is not highly dependent on uncertain future energy market prices.[12] Because its energy market revenues are fully hedged (for the contract duration), a CfD lowers investors' risk of project default (and risk of low equity returns). As a result, a CfD contract structure is more likely to meet its central goal, facilitating the entry and financing of new (or the retention of existing) qualified clean energy resources, than some other contract types. We have noted this fact in the fifth column of Table 1, scoring it as 'Low' among the listed contract types with respect to suppliers' revenue risk.

Suppliers' Bidding Complexity. There are several potential concerns with using a CfD contract structure at auction to procure clean energy, however. One is that it can be quite complex for a qualified supplier to determine its profit-maximizing strike price to offer in an auction. Its best offer must consider not only the minimum strike price that would allow the resource to be built, but also the energy market revenues that are passed up by 'locking in' the strike price for each MWh of energy production (e.g., its opportunity costs). Because many clean energy resources are intermittent, the correct strike price to offer at auction must therefore consider the expected energy prices in the hours in which the project will actually produce energy.

In auctions, bidding complexity matters. If suppliers' best offer prices are difficult for them to determine, it becomes more likely for suppliers to make bidding mistakes in the auction (submitting offer prices that are too high or low, for example). Offers that are too high raise consumers' costs unnecessarily, undermine auction competitiveness, and result in too little supply. At the other end, offer prices that are too low tend to cause default (that is, facilities not securing financing ex post and never becoming commercial). Such adverse outcomes could undermine the success of a FCEM,

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[11] A digression: Using *k* for strike is originally from baseball. Finance and baseball have long histories and many similarities (e.g., both involve pricing complex, tradeable assets, and both are loved by economists).

[12] If the buyer is a load-serving entity, buying a CfD also helps to hedge the buyer's risk of high energy expenses. In this way, a CfD differs from other risk management contracts that do not reduce risk for both buyer and seller but instead just transfer it to the other party, such as occurs with insurance contracts.

clearly, and have occurred previously in prominent infrastructure auction markets (such as federal wireless spectrum auctions).

Energy Market Offer Consequences. A CfD tied to generator's actual (real-time) energy production will distort the supplier's offer incentives in the day-ahead and real-time energy market. Because such resources will receive the auction-clearing strike price for each MWh of energy delivered, *regardless* of the energy market price, they have an incentive to bid in the energy markets at the ISO's energy offer price floor. Such behavior can depress energy market prices far below their competitive levels, and in certain operational conditions could exacerbate ISO operational challenges (managing minimum generation emergencies, for example). These issues could be addressed with special clawbacks and other contract provisions that help prevent suppliers from having incentives to produce when energy prices are negative or in situations that could create ISO operational challenges, adding to contract complexity.

Energy Put Contracts (Minimum Price Guarantees). An energy put contract (technically called a *real put option*) is a different contract type than a CfD. An energy put has two distinct pricing parameters. The strike price k represents the *minimum* payment that the supplier receives for each MWh of energy delivered, up to the contract quantity, q. Unlike in a CfD, however, the supplier gets paid the energy market price for each MWh of energy when the energy market price exceeds the contract's strike price. With an energy put contract, there is also a fixed monthly payment, commonly called the "contract price" (to distinguish it from the strike price) for each MWh that the seller is contracted to deliver.[13] In simple terms, and energy put contract is a minimum price guarantee.

Offer Elements. A version of the energy put contract framework was introduced by National Grid in the IMAPP meetings, and outlined as Option E.2B in the framework document. While not explicitly stated, it appears that these proposals would fix the contract price at $0 and require that resources submit strike price offers. The auction would then clear the set of qualified resources that submit the lowest strike prices, and award a contract to all cleared resources at the marginal resource's strike price.[14]

There are other ways to construct an auction with an energy put contract structure to incent investment in new renewable and low-carbon resources. For example, rather than holding the contract price fixed at $0 and requiring qualified suppliers to submit strike price offers, the design could use a fixed strike price (i.e., specified in advance before the auction) and require qualified resources to offer contract prices in the auction.[15] This is (arguably) the more conventional structure of put

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[13] Because a put option allows the supplier to reap the benefits of high energy market prices while being protected from low energy market prices (while buyers are exposed to high prices without receiving the benefits of low prices), the contract price typically specifies a payment from the supplier to the buyer.

[14] Available at http://nepool.com/uploads/IMAPP_Presentation_National_Grid.pdf and http://nepool.com/uploads/IMAPP_20160914_Framework_FCEM.pdf.

[15] Furthermore, it is possible to allow resources to select both a contract price and a strike price as part of their offer. While such a design gives resources more flexibility in their offers, a (much) more complicated auction design is necessary to determine which supply offers are accepted and the proper market-clearing

option contracts. Proponents of an energy put FCEM construct would ultimately have to determine which price parameter is held fixed (and at what value) when determining FCEM positions, and – importantly – why.

Supplier's Risk. When compared to a CfD, an energy put contract increases the risk for both the supplier and buyer, as total revenues now depend on the contract price, the strike price, and (in part) realized energy market prices. This risk is asymmetric, however, as suppliers are paid no less than the strike price for each MWh of energy delivered. When energy prices are high for an extended period, buyers are not afforded the same protection as with a CfD (they do not receive a partial hedge against high energy prices).

Importantly, an energy put contract is a financial arrangement that is familiar in energy project finance, and is a well-understood (by investors) means to limit resources' risk exposure to uncertain future energy market prices. Many merchant gas-fired plants are financed, in part, using energy put contracts that shift the risk of low future energy prices away from the project's owner(s) and toward a third-party financial entity (who charges a negotiated up-front fee – the contract price – in consideration for this service). This arrangement is commonly coupled with the project's debt financing as it may enable greater leverage (lowering total project costs); the energy put contract helps to protect lenders against insufficient energy revenues to cover the project's debt payments.

Supplier's Bidding Complexity. Because a supplier's FCEM revenues under an energy put are a complicated function of the strike price, real-time energy prices, and the contract price, this design makes it more challenging for suppliers to calculate their best FCEM offers than under a CfD. This is largely the same problem that arises in negotiating the proper up-front contract price for an energy put contract in merchant finance applications, however, and financial players backing new clean energy projects in New England are likely to have experience with this contract type. Nonetheless, the same concerns about bidding complexity in auctions (that is, the possibility of errors and their adverse consequences) discussed with regard to CfDs will also apply with energy put contracts, in general.

Energy Market Offer Consequences. An energy put contract, when tied to a resource's physical MWh output, will produce similar distortions to energy market prices as a CfD arrangement: qualified suppliers will receive no less than the strike price even if energy prices fall below this value. This minimum price guarantee will create a strong incentive to bid into the energy market at the floor in order to maximize output, thus distorting energy market prices downward and, at times, potentially presenting operational challenges when energy output at the resource's location (or system-wide) must be curtailed.[16]

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prices.

[16] As noted with CfDs, at the cost of contract complexity, special contract provisions can help prevent suppliers from having incentives to produce when energy prices are negative or in situations that could create ISO operational challenges. Further, the specifics of the incentive to bid at the energy market's offer price floor may depend on whether the FCEM pays the greater of the strike price and (i) the day-ahead energy price, (ii) the real-time energy price, or (iii) the price when the resource's offer was cleared. Additional analysis would

Fixed Price Adder Contracts. Under this third contract type, the FCEM compensation does not replace a supplier's energy market revenues. Instead, it specifies a fixed price adder that is paid to the qualified resource for each MWh of energy delivered (up to its contract quantity), *in addition* to the resource's energy market payment. Much like the energy put contract, there are two price parameters: the price adder (again denoted *k*) and the contract price (which we'll denote *v*).

Offer Elements. A price adder design could specify the contract price at $0 (say), while clearing the set of resources that offers the lowest price adder. This set of parameters appears consistent with Option E.2A from the framework document and possibly with the FCM-C concept outlined by CLF,[17] where the contract price is fixed at $0 and the market clears the set of resources that submit the lowest price adders. Much like with an energy put, there are also other ways to award FCEM positions and set the terms of an adder contract. For example, the auction could instead specify in advance a fixed price adder (at, say, the average social value of carbon displaced per MWh in New England's system), and at auction then require qualified resources to submit contract price offers.

Supplier's Risk. A price adder contract design is not typical in energy project finance because it does not provide either the supplier or the buyer with a hedge against uncertain future energy market prices. Instead, such a contract would require the buyer to pay a premium for each MWh of energy delivered by qualified resources. As a result, while this contract structure may facilitate the entry of qualified resources by increasing their expected revenue, it is unlikely to fare as well as CfDs or energy put contracts at lower the costs of financing the investment; a price adder contract does not reduce the volatility (in the precise sense of that term) of the project's energy market price risk.[18] For this reason alone, this contract type is unlikely to be as successful as other contract types at inducing new resource investment.

Supplier's Bidding Complexity. Although this contract design is uncommon, when structured as a stand-alone contract (that is, not co-optimized as part of the FCM), a supplier's profit-maximizing offer problem is not nearly as complex as with an energy put contract or a CfD. This is because there are no risk-transfer elements in a price adder contract, and such complexities therefore do not need to be modeled when a supplier formulates an expected profit-maximizing offer price. This simplicity is perhaps the principal benefit of this contract type.

Energy Market Offer Consequences. One benefit of the fixed price adder contract is that, relative to either a CfD or energy put contract, the distortionary effect of a price adder on energy market prices is more modest. Qualified resources would still have an incentive to decrease their energy supply offer prices below their true marginal costs, by an amount equal to the price adder (which is likely to be not nearly as low as the ISO's energy offer price floor.) As an analogy, the offer price distortion

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be necessary to evaluate these alternatives in detail.

[17] A caveat: The offer price format of the FCM-C approach is discussed by CLF conceptually, not precisely, so we are inferring here. See slide 13 of http://nepool.com/uploads/IMAPP_20160914_Presentation_FCM-C.pdf and, for the Framework document, http://nepool.com/uploads/IMAPP_20160914_Framework_FCEM.pdf.

[18] Put in statistical terms, a fixed price adder contract does not reduce the *variance* of the project's risky stream of future energy market revenue.

with a fixed adder contract is analogous to how eligible resources currently internalize production tax credits in their energy market supply offers.

Minimum Delivery Obligation Contracts with Shortfall Penalty. Various FCEM proposals during the IMAPP process referred to a shortfall penalty if the seller fails to deliver its full contract quantity.[19] In these discussions and the FCEM framework document, this penalty has been discussed as a component of broader designs for qualified clean energy suppliers. The broader designs may take the form of a CfD, energy put, price adder, or an alternate contract design.[20] However, because the inclusion of a shortfall penalty is not part of a standard CfD, energy put contract, or price adder contract, we discuss such a feature here separately.

As a stand-alone design, a minimum delivery obligation with a shortfall penalty has both positive and less desirable features. It is a simple contract form: Suppliers bid on the up-front contract price at auction, and receive the LMP for each MWh produced (via the ISO's energy market settlements). There is then a contractually-specified shortfall penalty rule applicable to each MWh awarded in the contract but not delivered. Provided the contract quantities are below suppliers' expected production, this design tends to have little (if any) distortion on suppliers' energy market offer prices – a good thing. On the other hand, this simplicity has a cost: It leaves suppliers bearing much greater risk than they would under a pure CfD or energy put contract design.

In the IMAPP process, the minimum delivery obligation with a shortfall penalty approach has been discussed *in combination with* the other contract types noted previously.[21] This complication makes it difficult to evaluate confidently the properties in Table 1 for a contract that is, in effect, a smorgasbord of two different contract types. With that disclosure on our part, a few implications are likely. First, if the penalties for non-delivery are significant, the contract structure may depress real-time energy prices because qualified resources may submit energy market offers as low as to the shortfall penalty rate to ensure they meet their forward obligation and avoid paying penalties.

Second, and potentially more importantly, a high shortfall penalty can inefficiently increase a supplier's risk and therefore the project's cost. This can also exacerbate suppliers' bidding complexity in ways that are difficult for them to model and price into their FCEM supply offer prices.[22] Unless the

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[19] For example, see slide 13 of CLF's October presentation at http://nepool.com/uploads/IMAPP_20161006_Presentation_CLF_FCM-C.pdf.

[20] In the FCEM framework document, the decision of whether to include a penalty for non-performance (Options E.4A and E.4B) is presented as distinctly separate from that outlining how resources are paid for the clean energy they deliver (Options E.2A and E.2B).

[21] Normally, with financial CfDs, option contracts, and other two-settlement contract designs, the consequence for not delivering the contract quantity is to pay the underlying good's spot price (in the context of clean energy, that might be approximated by the spot price of energy in the ISO's markets plus the spot market price of RECS). Adding to those contract types an express shortfall penalty is a more arbitrary provision that presumably seeks to serve a similar purpose.

[22] Additionally, IMAPP proposals including a shortfall penalty leave many open questions. For example, if there is a charge for delivering less than the supplier's forward position, should there also be a credit to resources that deliver more than their forward position (as in Pay for Performance), and if not, why not? Is

shortfall penalty is closely aligned with an economically-sound measure of the buyer's actual harm from a shortfall of 'clean' energy (relative to the putatively non-clean energy produced instead), the addition of such a provision may unnecessarily drive up suppliers' overall risk – and, therefore, may serve to undermine the FCEM's overall goal to promote new (and retain existing) clean energy projects.

Issue 2: Governance of FCEM Qualification and Demand

Prior to the procurement of clean energy through a FCEM, the region must determine what resources are eligible to provide the product. Unlike carbon pricing, where the relevant attribute (carbon emission) is priced directly, the determination of what resources qualify to compete in a FCEM will produce discrete winners and losers based on how the rules are set (rather than based on energy prices alone).[23] In addition to determining eligibility, the qualification process must also develop a robust methodology to determine how many MWh of clean energy each qualified resource is permitted to bid into the market.[24] To ensure that a FCEM functions as a competitive market, the qualification criteria must allow numerous potential market participants to submit offers. Put another way, if FCEM qualification rules are narrowly specified as a means to clear specific resources, a FCEM would not constitute a competitive market at all – and should be instead regarded as little more than an alternative administrative means to award out-of-market contracts.

In addition to the eligibility criteria, the region must also determine how much clean energy to procure. This demand will be dependent on state policy objectives and could be represented as a fixed MWh quantity, or as sloped demand curve that specifies a higher willingness to pay for additional clean energy when supply is tight and lower prices as the quantity increases. A sloped curve would require that the region develops more demand parameters, but would also help to mitigate year-over-year FCEM price volatility. Determining how this will be developed and adjusted over time, and if it is to be implemented within an ISO tariff ultimately adjudicated by the FERC, may require substantial deliberation and regional cooperation.

Some FCEM proponents have expressed interest in procuring multiple FCEM products (e.g. peak versus non-peak hours, or differentiated FCEM products to meet specific state policy objectives). Each of these would require a separate qualification process and the specification of its own demand parameters, thereby adding to the complexity of the design.

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there a 'buffer' such that a resource that delivers 1 MWh less than its obligation does not incur a penalty? As these questions illustrate, the methodology must precisely define how performance is measured and how any second settlement is determined.

[23] For example, FCEM proposals have not reached a consensus on whether nuclear units or existing renewable resources are eligible to sell their clean energy in a FCEM. Furthermore, the qualification governance process would need to be able to incorporate new and emerging technologies as they enter the wholesale market.

[24] This MWh determination is especially important in cases where there is no second settlement, or the charge for under-delivering relative to one's contract quantity is small. In such cases, resources may have a strong incentive to bid the maximum MWh quantity they are permitted to offer.

Issue 3: Mitigation in the FCM

Under the Minimum Offer Price Rule (MOPR), new resources are only allowed to include expected revenues that are 'in market' in their FCM supply offer. While current rules allow expected REC and renewables' federal tax credits to be counted as 'in market' because they are technically available to any market participant, they exclude revenues from privately negotiated power purchase agreements at above-market rates. This rule is designed to protect competitive suppliers from the effects of buyer-side market power, which can produce damaging, inefficient outcomes that undermine the commercial viability of future market investment.

There appear to be different approaches in the FCEM proposals as to whether the FCEM revenues are considered in market for purposes of applying the MOPR, or if these revenues are instead to be excluded from capacity market supply offers. Characterizing FCEM revenues as 'in market' would help new qualified clean energy resources clear in the FCM because eligible resources could lower the FCA supply offers below what would otherwise be permitted under the MOPR. Importantly, however, the resulting outcome could be functionally equivalent to exempting the new clean energy resources from the MOPR provisions entirely. That would *de facto* produce the same outcomes as out-of-market contracting to exercise buyer-side market power – although not by intent of the FCEM, but rather as an unintended consequence. That unintended consequence would undermine the FERC's and the ISO's long-standing efforts to protect the capacity market's integrity, as a means to ensure it can attract and maintain (non-subsidized) investment when needed.

In summary, this potential consequence of a FCEM heightens the importance of developing complementary design changes to the FCM that can accommodate the states' interest in promoting clean energy while preventing potential capacity price suppression that undermines the commercial viability of non-renewable generation investments needed for power system reliability.

Issue 4: Auction Designs

At the outset, it is important to determine the contract type before the auction design and mechanics are developed. Once the FCEM contract type and its essential terms are determined, an important consideration becomes how and when a FCEM auction is run. Given its objective to send forward price signals to incent investment in qualified clean energy resources, it is expected that the procurement would take place several years before the delivery period at approximately the same time as the FCA.

The key features of a strong FCEM auction design – including such basics as what a supplier's offer price actually represents – are dependent on numerous elements that have not yet been fully developed in the IMAPP process. Examples of these elements include which price parameters are fixed in advance and which are biddable parameters for suppliers (and why), and whether contract quantity offers can be partially cleared or are non-rationable (indivisible, or "lumpy" offers). Furthermore, while an auction may award initial forward positions, proponents must determine how to provide opportunities for resources to modify their forward positions prior to the delivery year through reconfiguration auctions, bilateral trades, buying out their obligations financially (or only via default), and so on. While this added flexibility will generally lower procurement costs and help the market allocate the forward clean energy contracts to the resources who can deliver at least-cost, it will also add substantial time and effort to the detailed design work.[25]

Co-optimizing the FCM with a FCEM. Some FCEM proponents have highlighted the potential benefits of a co-optimization process where resources would offer to sell two different products (capacity supply obligations, in MW, and forward clean energy obligations, in MWh). Further, these proposals appear to contemplate qualified suppliers submitting a *single* price reflecting the minimum revenue that the resource must receive to accept forward obligations for *both* of its submitted quantities (resources not eligible to deliver clean energy would have a FCEM quantity of zero MWh). The market would then jointly clear both capacity supply obligations (in MW) and forward clean energy obligations (in MWh) to maximize total social surplus. Because resources do not separately specify a per-MW capacity price and a per-MWh clean energy price, to ensure each cleared resource is paid at least its combined offer price, such a design would appear to require that all offers are non-rationable (i.e., each resource either clears its entire capacity *and* its entire clean energy offer, or nothing).

While jointly clearing a forward capacity and forward clean energy auction may be theoretically possible, it presents numerous practical concerns – and may well be infeasible. As an initial matter, requiring suppliers with very different costs, technologies, etc., to submit a *single* price for *two* different products generally does not produce least-cost auction outcomes. To properly procure multiple products simultaneously in a single auction, suppliers are usually permitted to submit at least two prices (one for each product, and sometimes additional offers for various combinations of the two products, depending on suppliers' underlying costs, risks, and technologies). These multi-product, multi-price auction designs can be extremely complex, non-transparent in their mechanics, and may require a lengthy effort by specialized auction theory experts to adapt such designs to the present context successfully.

A second challenging issue arises if suppliers submit FCEM offer quantities that are non-rationable (that is, lumpy or all-or-nothing offers). Presently, the FCA allows participants to submit capacity supply offers that are non-rationable (in whole, or in part). Clearing the existing FCA with these non-rationable offers has proven to be a significant mathematical challenge, for which the ISO uses specialized algorithms and software that exploit many special features of the FCA (importantly, that each resource offers a single product).[26] These specialized auction-clearing methods may not generalize to "lumpy" auctions where each resource can offer multiple products. At bottom, the ISO cautions that it is likely to require significant time, effort, and expertise to develop, test, and confirm that such an auction is technically implementable and could clear resources' offers properly. Although we do not have direct experience implementing such a complex auction to date, we must

[25] Any reconfiguration auction and bilateral rules must carefully crafted to prevent arbitrage opportunities and ensure that cost-effective set of resources holds the FCEM obligations during the delivery period. The demand for opportunities to update a FCEM position may be dependent on the contract design, as resources are likely to want significant flexibility if there is a shortfall penalty.

[26] These specialized algorithms are part of the FCA's market clearing engine, which runs after the close of the Descending Clock Auction. For a summary, see https://www.iso-ne.com/static-assets/documents/2015/11/20151202_fca_clearing.pdf.

caveat that properly clearing an auction with lumpy offers for multiple products may not prove technically feasible, and market clearing prices in this context may be ill-defined or may not even exist.

Two-tiered Pricing in the FCA

Unlike the previous proposals addressed in this memorandum, the two-tiered pricing concept discussed in the IMAPP process to date does not aim to reduce carbon emissions directly.[27] Instead, it presumes that states will continue to execute long-term contracts with preferred new resources (at potentially above-market prices) to meet their environmental and policy objectives, and it attempts to curb the impacts of these contracts on the capacity price paid to other suppliers. This design was introduced by NRG and was discussed in detail in NESCOE's October 18th memorandum.[28] It is similar in certain respects to a design concept that has been discussed in PJM, and that would also use separate market clearing engine runs to set prices and award capacity.[29]

The basic two-tier concept proposed by NRG is achieved by using the FCA's market clearing engine twice, with different supply offer prices for resources with out-of-market subsidies. A first pass retains the MOPR for resources receiving out-of-market subsidies, runs the FCA market clearing engine as usual, and determines a "first-tier" capacity price to be paid to non-subsidized resources (or, more precisely, paid to their MW that will be awarded capacity supply obligations (CSOs)). The first pass does not, however, determine the CSOs awarded to each resource. That is done in a second pass. The second pass modifies the subsidized resources' supply offer prices to allow the out-of-market revenue (that is, it no longer applies the MOPR), and determines a "second-tier" capacity price for resources awarded a CSO that receive out-of-market revenue. As a final step, there is a "pro-rationing" adjustment to determine final CSO awards: Infra-marginal resources receive lower final CSO MW awards than they would if based on the first pass alone, in order to account for the additional supply from subsidized resources awarded CSOs in the second pass.

A graphical example. In order to explain some of the ISO's concerns below, a simple graphical example will be useful. Consider Figure 1 below. It depicts a hypothetical capacity market auction scenario, using a supply and demand diagram. Three different supply resources, A, B, and C, are owned by competitive suppliers. A fourth supply resource, S, is a new state-subsidized resource that has higher true costs than the other resources, but receives an out-of-market subsidy that would enable it to profitably offer capacity at a price near $0 (in the absence of the MOPR, that is).

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[27] This approach has been cogently articulated by NRG in the IMAPP process; see http://nepool.com/uploads/IMAPP_20160914_Framework_NRG_rev.pdf, http://nepool.com/uploads/IMAPP_20160830_Presentation_Two-Tier_Pricing.pdf, and http://nepool.com/uploads/IMAPP_20161110_Two-Tier_Pricing.pdf.

[28] Available at http://nepool.com/uploads/IMAPP_20161021_NESCOE_2Tiered_Pricing_Analysis.pdf.

[29] PJM's design was discussed in a memo available at See http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/grid-2020-focus-on-public-policy-market-efficiency/meeting-materials/20160816-potential-alt-solution-to-the-min-offer-price-rule-for-existing-resources.ashx.

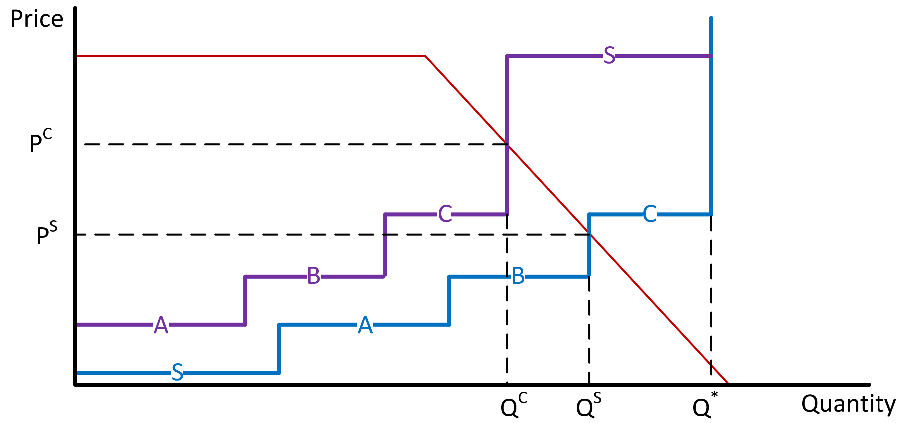

Figure 1

Two Price Determinations. The first pass uses the purple (upper) supply curve and determines the competitive "first-tier" capacity price, denoted in Figure 1 by P^C, that occurs when the MOPR is applied to resource S.

The second pass does not apply the MOPR, in which case resource S is offered at a low price that incorporates its out-of-market revenue. This results in a different, blue (lower) supply curve. Supply and demand now intersect at a lower "second-tier" price than before, denoted in Figure 1 by price P^S.

Resources A, B, and C offered below the first-tier price P^C, and will be paid P^C for each CSO MW they are ultimately awarded. Resource S will be paid the second-tier price of P^S (as will, in more general situations, any other subsidized resources with mitigated offer prices above P^C in the first pass, but that are ultimately awarded a CSO after the second pass).

CSO Award Determinations. In the second pass, the market would clear a total amount of capacity (in MW) denoted by Q^S in Figure 1. This is where the second-pass supply curve intersects the demand curve. However, note that if the full offered MW of resources A, B, C, and S are all awarded CSOs, the sum of their offered capacity (shown as Q^* in Figure 1) would exceed the total market-wide CSO MW to be awarded in the second pass (equal to the lower amount Q^S). Under the NRG proposal, to accommodate this discrepancy, the awarded CSO MW for each resource would then be pro-rated down; specifically, each resource A, B, C, and S would receive a reduced CSO MW award so the total auction payments remain equal those of the "competitive" first pass (or the product of P^C and Q^C, in Figure 1).

Summary Observations

As highlighted in IMAPP presentations of this two-tiered pricing proposal (and earlier in this memo, under Issue 3 in the FCEM discussion), allowing resources to include out-of-market payments in their supply offers without any adjustments could create inefficient consequences similar to the exercise of buyer-side market power. The two-tier pricing proposal is one of many possible ways to address this concern, where each involves trade-offs among various concerns and design issues.

It is important to note that the NRG approach consists of two distinct elements that are not directly related. One is the use of two different prices, which pay resources with an out-of-market payment a lower capacity market price than competitive suppliers. The second, distinct element is the award pro-rationing method, applied to ensure that the market produces the same total auction payment as under the (first-pass) scenario where no subsidized resources are awarded CSOs.

Because alternate designs could include one of these two elements, while excluding or modifying the other, it is useful to separately evaluate the implications of paying two different prices pricing and the award pro-rationing method.

Practical Issues and Concerns

We discuss the two distinct elements noted above separately, starting with the pricing rules.

Price Discrimination Concerns. The ISO has not discerned the benefit of paying resources receiving an out-of-market payment a lower capacity price than competitive resources. It would result in paying different prices to resources that acquire identical performance obligations. Further, this design feature is unlikely to materially reduce total consumer costs, since the increased capacity costs that would result from paying the higher, competitive clearing price to all capacity awarded CSO MW would be offset by reduced out-of-market payments to the subsidized resources.

As a separate concern, while paying a lower capacity price to subsidized capacity is unlikely to impact total consumer costs, it may be controversial with the ISO's regulator (FERC), which has expressed concern in the past with designs that pay different prices to resources that are taking on the same capacity supply obligations.[30]

Pro-rationing CSO Awards Implications. Under the CSO pro-rationing method, cleared resources may not receive a CSO award for their entire qualified capacity, even if it is all offered below their (applicable tier) clearing price. Instead, all cleared resources will see their awards pro-rationed to ensure that the total auction payments are not impacted by the subsidized resources. The ISO has identified two ways in which this pro-rationing rule may produce incentives and outcomes that are inconsistent with good market design. These are discussed next.

Offer Price Inflation. If a resource has some fixed total capacity revenue it needs to ensure its resources remains commercially viable (to continue operating or to develop as new), then the rationing rules in NRG's proposal can be expected to lead the resource to increase its capacity supply offer prices above its competitive per-MW offer price (that is, in the absence of the pro-rationing method). This will ensure the resource receives the same total capacity revenue from a smaller number of cleared MW, if it still clears – and, thereby, avoids the adverse situation in which a resource

[30] See FERC's April 13, 2011 Order rejecting an earlier ISO two-tiered pricing proposal, at https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12619222.

acquires an obligation in consideration of too little revenue to continue operating during the delivery year.

If many resources adjust their bids in this manner, which should be expected, capacity prices will increase accordingly – and consumer costs will increase over time. That is, this pro-rationing method is not neutral with respect to total capacity costs over time. For a more detailed discussion of how the pro-rationing method creates this incentive, see the NESCOE October 18th memo referenced earlier.

Initial Awards and Re-trading. There is a second concern with any pro-rationing method that has not been fully appreciated during the IMAPP discussions to date. In particular, the implications of the pro-rationing method for re-trading in the Reconfiguration Auctions or through CSO Bilateral trading do not appear to have been fully contemplated.

As an initial observation, the pro-rationing method produces plainly inefficient FCA outcomes: it does not clear the lowest-cost capacity, even among the non-subsidized resources. This can be seen in the example above, as the last MW of from resource A is not cleared, whereas much of resource C's higher priced offer is awarded a CSO. While this inefficiency may seem small, its implications may be significant. Specifically, market forces will make it profitable to re-trade obligations so that the lowest cost suppliers hold them prior to the delivery period, even if an initial FCA method (such as the pro-rationing of CSO awards) does not initially award capacity to the lowest cost suppliers.

To see the potential concern, consider again the example in Figure 1. After the FCA is over, Resource C could trade some of its cleared CSO MW (via a reconfiguration auction or bilaterally) to the lower-cost qualified capacity MW of Resource A that did not get an initial obligation due to the rationing method. This trade can benefit the profitability of both capacity suppliers, as Resource C earns a profit from shedding capacity at a price below P^C, whereas Resource A earns lower (but still profitable) capacity market revenues on the portion of its unit that was initially pro-rated.

As a result, the pro-rationing method may serve as a mechanism to create additional profit for the higher cost, non-subsidized resources do not deliver capacity during the commitment period, and that would not be awarded CSOs in the first place in an efficient auction design. This concern does not appear fixable under a CSO pro-rationing method, for a fundamental economic reason: markets will profitably re-trade forward obligations to the set of suppliers that have the lowest cost of fulfilling those obligations, if an initial allocation method does differently.

Conclusion and Potential Next Steps

This memorandum provides the ISO's observations on the three major conceptual designs that have been presented during the IMAPP process. These observations suggest several summary observations.

First, when evaluating the designs that aim to directly reduce carbon emissions using three standard criteria of good market designs – simplicity, transparency, and cost-effectiveness – carbon pricing approaches in the energy market are likely to be superior to a FCEM, on all three criteria. As noted at the outset, however, carbon pricing and a FCEM are not mutually exclusive.

Second, because it involves developing a completely new product, auction system, and contract administration process by the ISO, creating a FCEM is likely to be a lengthy, multi-year endeavor and present high demands on the ISO's resources (and stakeholders). However, ISO-administered carbon pricing may also not be implementable quickly inasmuch as the novelty of the jurisdictional issues it poses may create delays while legal issues are resolved. As a result, while ISO-administered carbon pricing in the energy market or a FCEM may have longer-term usefulness, the ISO does not anticipate that pursuing either would be a practical path for accommodating state public policy objectives in competitive wholesale electricity markets in the short term.

Finally, a two-tiered pricing proposal aims to satisfy a different objective: rather than reduce carbon emissions directly, it seeks to accommodate the entry of state-subsidized renewables into the capacity market while attenuating their potential suppression of FCA prices for existing resources. While the ISO agrees that this broad objective is reasonable, the ISO has significant concerns with the specific two-tiered pricing design put forth during the IMAPP process as discussed above. Instead, the ISO expects that with further analysis, there may be alternative design changes to the FCM rules and/or MOPR that may achieve the broad objectives of this two-tier pricing proposal, but without the concerns identified above with this specific design.

Next Steps

While many of the conceptual solutions offered in this process are still in the early stages, and perhaps some could overcome the issues discussed in this memo with additional time and consideration, there may also be other, new approaches. Some new or refined proposals could continue to target the broad objective of achieving state policies through markets (rather than through contracts above market-rates). Others may focus more narrowly on avoiding price suppression in the capacity markets while accommodating state-sponsored resources in the capacity markets when such contracting takes place.

For example, the MOPR was designed to prevent certain contracted resources from destabilizing investments in the market developed to maintain resource adequacy. From the ISO's perspective, revisions to the market rules to address this issue, while accommodating state policy objectives, is a pressing matter that should be addressed in the near-term. While some smaller state-contracted investments are likely coming to fruition as early as FCA11, a potentially larger influx (by MW) of state-contracted supply could impact the markets as soon as FCA13, based on recently-enacted state legislation.

Taking the IMAPP discussions into consideration, the ISO is examining whether there are alternatives or enhancements to the FCM rules and/or MOPR that could be employed in the near-term to address the potential infusion of state-backed resources seeking capacity supply obligations. With some lead time, the ISO anticipates being able to develop a concept to help accommodate state policies while preserving the integrity of capacity market pricing. The concept could be considered by stakeholders along with those already under consideration in the IMAPP process. The ISO would plan to be ready to discuss its idea with stakeholders by May 2017 in order to obtain feedback on the possible tradeoffs and outcomes of the proposals by the ISO and others.

Given the announced timing of the Massachusetts clean energy solicitation and the relevant steps in the annual FCM process, the ISO believes that if a promising proposal is developed to address new state-subsidized resources, it should be filed with the FERC by the end of 2017. This would line up with the key FCM windows for FCA13 that occur in March 2018. Any potential proposals to address the near-term issues would likely need to begin the NEPOOL committee review process around June in order begin a deeper, technical evaluation with stakeholders. The ISO will discuss the timing and process of such an approach with NEPOOL officers in February to determine an appropriate path.