NEW ENGLAND POWER POOL

PROPOSED AGENDA

Integrating Markets and Public Policy (IMAPP)
Plenary Meeting #5
Friday, October 21, 2016
Renaissance Providence Downtown Hotel, Providence, RI

Morning Session **9:30 a.m. - 12:00 p.m.**

- **Introductory Remarks**
- **Presentation and Discussion of IMAPP-Related Legal/Jurisdictional Issues**
- **Refinement and Discussion on Conceptual Proposals**
  - Carbon Integrated Forward Capacity Market (FCM-C)

Lunch Break **12:00 – 12:30 p.m.**

Afternoon Session **12:30 – end of day (estimated to be 4:00 p.m.)**

- **Continued Discussion on Conceptual Proposals**
  - FCM Two-Tiered Pricing Construct
- **Discussion and Feedback on Post-Oct. 21 IMAPP Process and Scope**
- **Concluding Remarks/Discussion of Next Steps**

Integrating Markets and Public Policy (IMAPP): Overview of Legal & Jurisdictional Issues

October 21, 2016

Presented by:
NEPOOL Counsel

DAY PITNEY LLP

Presentation Overview

- FERC's Jurisdictional Authority
- States' Authority & Responsibility
- Recent Supreme Court Cases
- IMAPP: Threshold Legal/Jurisdictional Issues
  - FERC's jurisdictional authority
  - Undue discrimination or preference
  - Cost allocation issues
  - Preemption issues
  - Other issues?

FERC's Jurisdiction -- Overview

- FERC only has the jurisdiction given to it by Federal statute
- The applicable statute here is the Federal Power Act ("FPA")
  - FPA gives FERC jurisdiction over "that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States." **FPA Section 201**
  - "Public Utilities" must file with FERC "rates and charges … and the classifications, practices, and regulations affecting such rates and charges." **FPA Section 205**
  - FERC must ensure that wholesale power rates and charges on file with it, including the practices affecting such rates and charges, are just and reasonable and not unduly discriminatory or preferential. **FPA Sections 205 & 206**

State Authority & Responsibilities

In general, States have exclusive jurisdiction over retail electric power sales, distribution, and generation siting

- The FPA has specific limitations of FERC's jurisdiction in Section 201
  - "[E]xcept as specifically provided" in the FPA, FERC jurisdiction does not extend, to "facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce."
  - FERC jurisdiction is over "the sale of electric energy *at wholesale* [i.e., for resale] in interstate commerce," but not over "any other sale," which is the domain of the states.

Some Relevant Landmark U.S. Supreme Court Rulings

- ***Montana-Dakota Utils. Co. v. Northwestern Pub. Serv. Co*., 341 U.S. 246 (1951)** – just and reasonable is a range–there is “a substantial spread between what is unreasonable because too low and what is unreasonable because too high.”
- ***Permian Basin Area Rate Cases*, 390 U.S. 747 (1968)** – within zone of reasonableness, FERC can employ price to achieve “relevant regulatory purposes.”
- ***NAACP v. FPC*, 425 U.S. 662 (1976)** – [FERC’s] authority to consider “public interest” is not broad authority to promote public welfare, but rather to further the purposes of the FPA.

Recent U.S. Supreme Court Rulings

- ***Oneok v. Learjet, Inc.*, 135 S. Ct. 1591 (2015)** – FERC's exclusive jurisdiction over wholesale rates does not pre-empt States' authority to enforce their antitrust laws, even if they affect the wholesale rates
- ***FERC v. EPSA*,136 S. Ct. 760 (2016)** – FERC has broad jurisdiction over practices directly affecting wholesale rates, even where those practices relate to demand response regulated by States
- ***Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct.1288 (2016)** – States do not have the authority to set wholesale power rates, directly or indirectly

IMAPP: Threshold Legal & Jurisdictional Issues

Issue #1

Does FERC' s jurisdiction extend to approval and regulation of environmental attributes in wholesale power arrangements?

- The FPA gives FERC broad and exclusive jurisdiction over wholesale power markets
- FERC must ensure that rates, terms and conditions of service, including practices, are just and reasonable and not unduly discriminatory
- FERC can use wholesale power arrangements to advance public interest purposes that are consistent with the FPA (*NAACP* and *Permian*)

FERC Jurisdictional Authority?

Acceptable

RECs that are part of a wholesale energy transaction

WSPP Inc., 139 FERC ¶ 61,061 (2012).

Compensation for Demand Response

FERC v. EPSA

“IT DEPENDS” on whether the attributes directly affect or are closely related to wholesale rates, terms and conditions

Unacceptable

RECs that are not part of wholesale energy transactions

Regulation of employment practices to eradicate discrimination

NAACP v. FPC

IMAPP: Threshold Legal & Jurisdictional Issues

<u>Issue #2</u>

Would rates, terms, and conditions of service (including practices) that differ based on environmental attributes be unduly discriminatory or preferential?

- The FPA prohibits ***<u>undue</u>*** discrimination or preference in rates, terms and conditions (including practices) of jurisdictional services

Undue Discrimination or Preference

- Different treatment in rates, terms and conditions is OK if differences are shown to be based on distinctions that FERC can properly consider under the FPA.
  - A rate is not unduly or unreasonably discriminatory or preferential if the disparate effect is justified based on factual, policy or other legitimate reasons.
  - The focus of undue discrimination or preference analysis will be whether there are legitimate reasons for the disparate treatment, including whether the recipients of the treatment are similarly situated.

Undue Discrimination or Preference?

Acceptable

2015-2018 Winter Reliability Program

"IT DEPENDS" on whether case has been made

Unacceptable

Exclusion of non-generation resources, such as demand response, in wholesale capacity market

IMAPP: Threshold Legal & Jurisdictional Issues

<u>Issue #3</u>

Can additional costs from IMAPP be assigned to entities that are not subject to the public policies driving those costs?

- Costs should be allocated in a way that is roughly commensurate with costs caused or benefits received.
- Costs should not be allocated to those who do not cause the costs or do not benefit from the service.

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IMAPP: Threshold Legal & Jurisdictional Issues

Issue #4

What level of involvement can States have in defining wholesale power market criteria or requirements?

- Any terms and prices set by a state and not sanctioned by FERC "[strike] at the heart of [FERC's] statutory power" under the FPA (*Hughes v. Talen)*
- "The FPA leaves no room either for direct state regulation of the prices of interstate wholesales or for regulation that would indirectly achieve the same result" (*FERC v. EPSA)*

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Preemption of State Involvement?

Acceptable

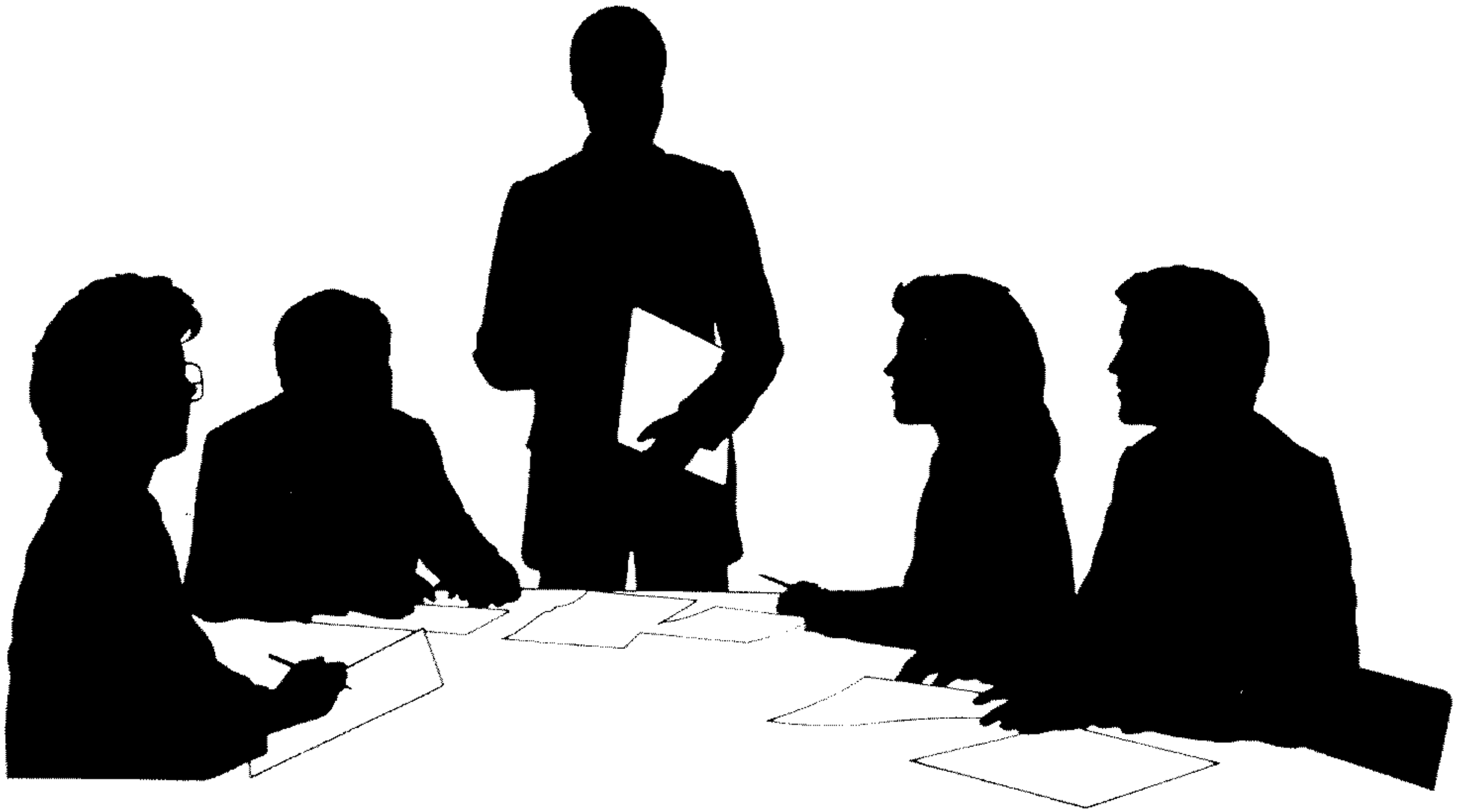
FERC requires that State input be considered by ISO and seeks to avoid conflicts if possible (e.g., development of ICR)

“IT DEPENDS”
on the degree
of state control over
setting wholesale
power rates, terms
and conditions

Unacceptable

States cannot set wholesale rates, terms and conditions (*Hughes v. Talen)*

Any other legal/jurisdictional issue(s) to consider?



FCM-C Mechanics

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October 21, 2016

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CLF's overall proposal has two components

1. Price on Carbon in Energy Markets -- Not discussed today.

2. Carbon Integrated Forward Capacity Market (FCM-C) *Provides an investment signal for the development of clean energy resources on a schedule consistent with the goal of 80% GHG reduction by 2050*

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Why Do Both CO_2 Pricing *and* FCM-C?

CLF does not argue that this combination is the only approach, nor necessarily the best option in all regions, but does see reasons to pursue this combination in New England

Component	Rationale
CO_2 Pricing	• Most critical element of the design proposal • Internalizes the externality; directly supports the design objective of decarbonizing • Will immediately introduce incentives to avoid CO_2 emissions in operations, retain existing clean resources, and attract new clean energy investments

FCM-C	• Indirectly supports the design objective of decarbonizing by supporting clean energy investments (indirect nature comes with some disadvantages)
	• May not be needed in every market, but reasons to adopt in New England:
	  • Many stakeholders supported a clean energy procurement in some form
	  • Introduces a more predictable quantity component to decarbonization (i.e. CO_2 pricing alone has less certainty on the timeframe and magnitude of reductions)
	  • Option to pursue differentiated quantity goals over time among states (CO_2 pricing would reflect a single combined objective and willingness to pay for reductions)
	  • Some stakeholders and states believe that forward certainty is needed to support clean energy investments, and FCM-C provides some with up to 7-year lock-in
	  • Opportunities to reconcile with state RPS, procurements, and ORTP
	  • Opportunities to reconcile magnitude, forward period, and delivery period of investment signals provided to clean energy and traditional capacity resources
	  • Technology-neutral and FCM-integrated approach provides opportunities to reduce costs of decarbonizing compared to status quo
	• Complements CO_2 pricing, with ZEC prices clearing lower given expected CO_2 price effect on energy

How Do FCM-C and CO_2 Pricing Address States' Policy Objectives and Concerns?

- **NESCOE Objective 1: Minimize Customer Costs, No State Policies Impose Costs on Other States**
  - Technology-neutral CO_2 pricing and ZEC procurement can achieve CO_2 reductions and clean energy targets at least <u>societal</u> cost
  - <u>Customer</u> costs more nuanced:
    - FCM-C ZEC procurement costs would be attributed only to participating states, avoiding any cross-payment
    - Treat FCM-C resources as in-market, reducing the quantity of capacity procurements that would be pursued if clean resources were excluded via ORTP
    - FCM-C on its own would also reduce energy and capacity prices for all participating and non-participating states
    - Adding CO_2 pricing on top would increase energy prices, but CO_2 charges are then awarded back to customers through direct offsets or EE programs
  - Net expected bill effect for customers in states <u>not participating</u> in FCM-C:
    - Likely that the net effect is a reduction in bills, up to a moderate CO_2 price
    - At very high CO_2 prices non-participating states would have higher customer bills than status quo
    - Modeling would be needed to provide clearer direction on the CO_2 price point above which non-participating states' customers would see bill increases

How Do FCM-C and CO_2 Pricing Address States' Policy Objectives and Concerns?

- **NESCOE Objective 2: ISO-NE Administered Auction as an Opt-in Option for States to Fulfill Clean Energy Procurements**
  - Opt-in approach: each state sets their own ZEC target quantity
  - However, because FCM-C is technology-neutral it may not be the right tool for pursuing all types of state policy objectives. Some objectives such as local jobs are not readily amenable to expression through competitive, technology-neutral markets
  - Technology-specific long-term PPAs might continue to be treated as out-of-market
  - States would have transparency in pricing of ZECs through the market, and use that information to inform going-forward plans (e.g. greater reliance on the ISO-NE administered ZEC market for procurements if that market shows lower cost)

How Do FCM-C and CO_2 Pricing Address States' Policy Objectives and Concerns?

- **NESCOE Objective 3: Enable States to Retain Existing Clean Resources**
  - Potential concern with status quo approaches is that adding more clean resources to the system can undermine the economics of existing clean resources and induce retirements. Potential to undermine ability to achieve CO_2 reductions by displacing existing clean resources rather than existing fossil generation
  - Technology-neutral FCM-C and CO_2 pricing would retain existing clean resources as long as they are the most cost-effective resources ("trigger" mechanism is an in-market cost-effectiveness test)
  - This approach avoids the need for out-of-market interventions to retain these resources, along with the potential adverse impacts on in-market resources

Review of FCM-C

- Two supply curves for two separate products in a single auction:
  - Capacity Product: Current definition of capacity megawatts; cleared resources acquire a CSO
  - New Product: Zero Emission Credits (ZECs) for producing megawatt-hours from non-emitting resources
- ZEC-eligible resources offer a single price (for both commodities) sufficient to meet their revenue requirement*
- Single price approach analogous to single energy market price that is applied to both energy and reserves markets
- ISO clears these offers using least-cost combination of the two products
- ISO clears both products simultaneously in the single auction

*Design will need to consider the most appropriate offer structure, e.g. to ensure that resources clearing for ZECs earn a sufficient additional capacity payment for taking on the pay-for-performance obligation, see subsequent slides on this topic.

Review of FCM-C (cont.)

- Each year the ISO develops two demand curves for the auction:
  - Capacity demand curve continues to be denominated in MW
  - New ZEC curve is denominated in MWh
- Denominating the ZEC obligation in MWh allows the ZEC generator to satisfy its delivery obligation at any time during the delivery year
- Clearing price for new ZEC resources comes with the same clearing-price lock-in provided to new resources clearing for traditional capacity (currently 7 years)
- Incumbent resources are not eligible for clearing price lock-in, but are eligible for ZECs

Review of FCM-C (cont.)

CLF's two-part proposal (carbon adder in the energy market + new ZEC market integrated with the forward capacity market) is technology-neutral

- ZEC market is open to both new and existing resources, e.g. existing nuclear plants are eligible
- Imported resources are eligible
- ZECs are a system-wide product, no locational differentiation
- Determining responsibility for and criteria for resource qualification will be a substantial area of refinement, ideally leveraging existing state REC qualification approaches and tracking systems for internal and imported resources (but need to acknowledge the substantial effort since approaches differ across states)

Please provide additional examples to illustrate how the co-optimized capacity and ZEC auction would clear

- We report a series of examples here in a narrative form, and provide detailed offer price and clearing results as an appendix in each case
  - Example 1: ZECs and ICR
  - Example 2: Wind is Marginal for ZECs; Gas is Marginal for Capacity (Same Example as in Previous Presentation)
  - Example 3:Nuclear Plant is Marginal for Both Products

Example 1: ZECs and the ICR

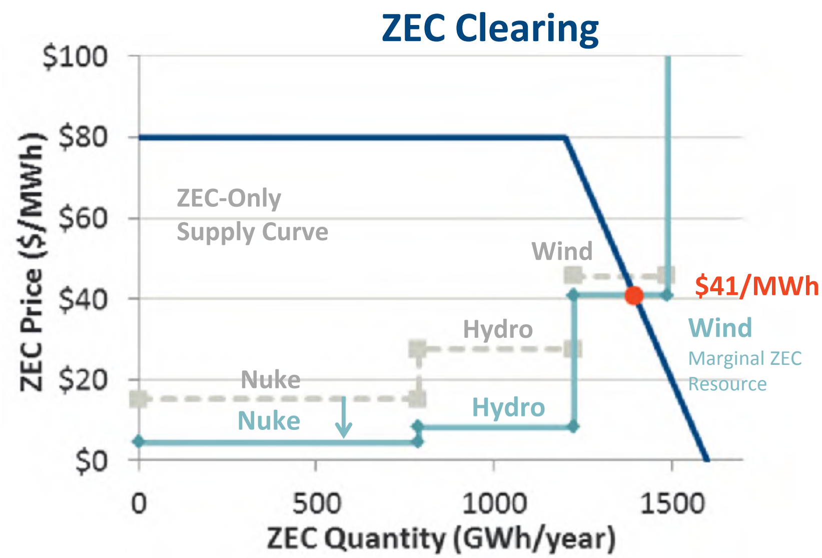
The Clean Green Wind Farm

Nameplate: 150 MW
Capacity Factor: 22%
Offers into FCA: 33 MW plus 262,800 MW**h** of ZECs
Unit clears: 33 MW plus 240,000 MW**h** of ZECs

- The 33 MW does count toward satisfying the ICR (just as all cleared MW that acquire a CSO count)
- The 240,000 MW**h** of ZECs to not count toward satisfying the ICR

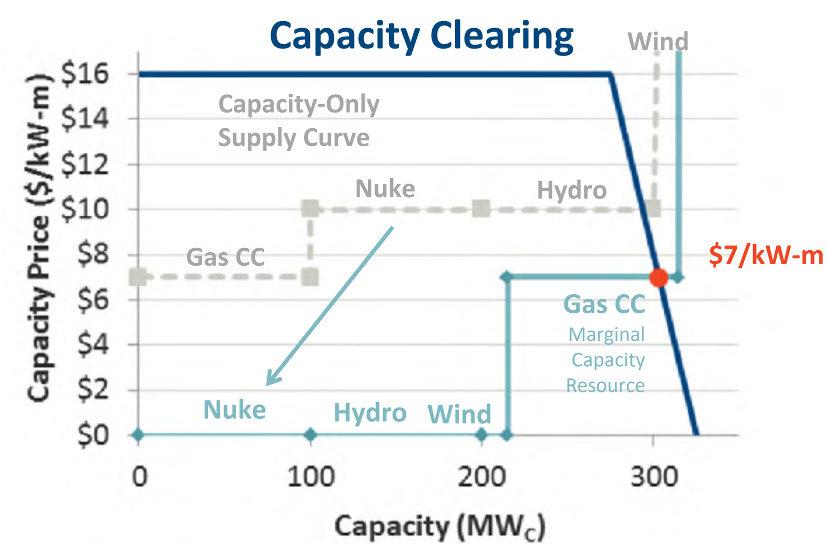
Example 2: Wind is Marginal for ZECs
Gas CC is Marginal for Capacity

- Same example as prior presentation
- Different resources are marginal for each product:
  - Wind is price-setting for ZECs (ZEC price clears below ZEC-only offer price based on capacity revenue earned)
  - Gas CC is price-setting for capacity
- Adding ZEC product changes merit order for capacity, some non-emitting resources displace some fossil resources



Resource Offers and Clearing Results

		Nuke	Hydro	Gas CC	Wind
Resource Ratings					
Nameplate	*(MW_N)*	100	100	100	100
Capacity	*(MW_C)*	100	100	100	15
ZECs	*(GWh/year)*	788	438	0	263
Offer Price	*($\$/kW\text{-}m_N$)*	$10	$10	$7	$10
Cleared Quantity					
Percent Offered	*(%)*	100%	100%	93%	64%
Revenues					
Total	*($\$/kW\text{-}m_N$)*	$34	$22	$7	$10

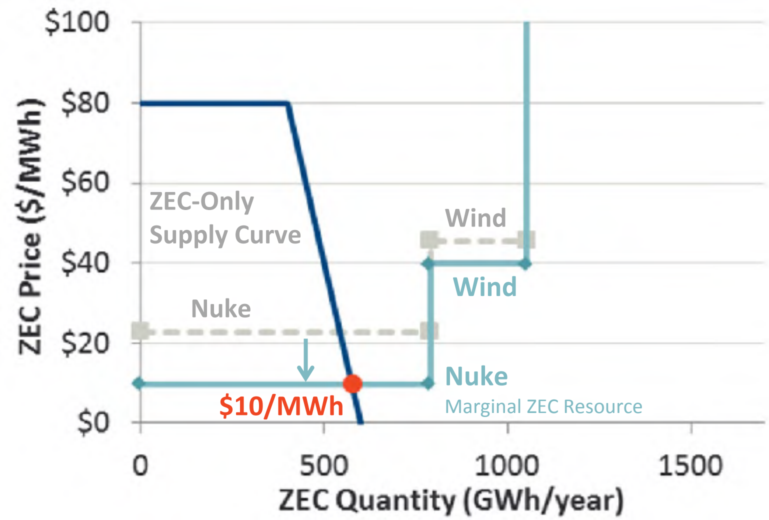


Notes: Supply curve for ZECs reflects minimum ZEC price that each resource is willing to accept, given the capacity clearing price. Similarly, supply curve for capacity reflects minimum capacity price each seller will accept once the ZEC price is known.

Example 3: Nuclear Plant is Marginal for Both Products

- Same resource can be price setting in both products
- Nuke offer price of $15/kW-m would have been price-setting for capacity without ZEC product
- Nuke plant's effective capacity offer price drops to $9/kW-m as price-setting for capacity once accounting for ZEC revenues

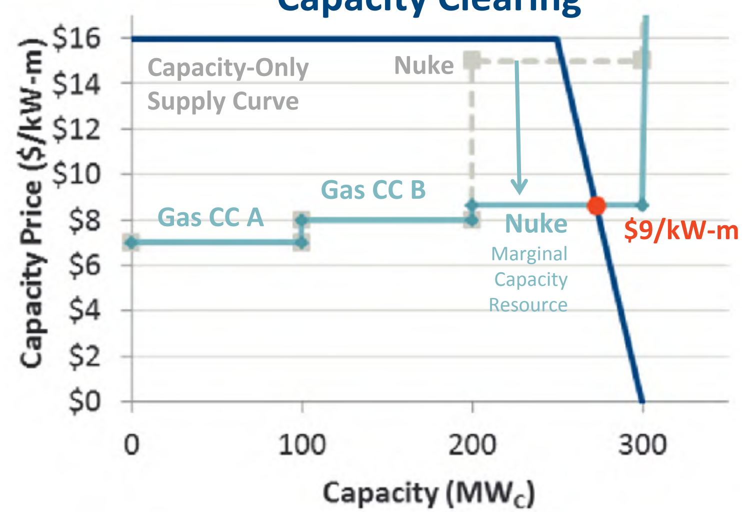
ZEC Clearing



Resource Offers and Clearing Results

		Nuke	Gas CC A	Gas CC B	Wind
Resource Ratings					
Nameplate	*(MW_N)*	100	100	100	100
Capacity	*(MW_C)*	100	100	100	15
ZECs	*(GWh/year)*	788	0	0	263
Offer Price	*($/kW-m $_N$)*	$15	$7	$8	$10
Cleared Quantity					
Percent Cleared	*(%)*	73%	100%	100%	0%
Revenues					
Total	*($/kW-m $_N$)*	$15	$9	$9	$0

Capacity Clearing



Is there a secondary market for ZECs?

Answer: Yes

- Reconfiguration auctions and bilateral trades.
  → Reason: Both ISO-NE and public policy are presumed to be indifferent as to who satisfies the ZEC obligation

- Bilateral trades can continue even into the delivery year.
  → Reason: Delivery requirement of MWh can be any time during the delivery year; both ISO and public policy continue to be indifferent as to who satisfies the obligation, even during the delivery year

Are there performance obligations for ZECs?

Answer: Yes (but not like pay-for-performance)

- Obligation is to produce clean energy MWh during the delivery year, with financial implications for under-delivery (and likely incremental payments for over-delivery)
- Need to work out details to fully specify the product definition, ensure appropriate interactions with energy market, and ensure settlement incentives align with the policy objective of reducing carbon (all FCEM and ZEC proposals will face these same questions)

Performance obligation for ZECs? (cont.)

- In-Year Settlement Options:
  - Resource does not get paid absent delivery
  - Deficiencies and over-delivery could be settled against a final reconfiguration auction at the end of the delivery year, using the same demand curve as in the original FCM-C auction
  - Another option is to allow some banking/borrowing between delivery years
  - A final option is to explore whether settlements should be tied to the CO_2 component of LMP during delivery hours (which would be more complicated and not consistent with REC definition, but could recognize that some resources' output profiles are superior to others in terms of achieving the decarbonization objective)
  - Financial penalty for failure to achieve benchmark set by ISO-NE (e.g. 90% of MWh promised)

Performance obligation for ZECs? (cont.)

- In-Year Settlement Options (cont.):
  - Need to carefully examine the implications of deficiency settlements on offer and dispatch during minimum generation conditions in the energy market. For example, to avoid very negative prices when there is overgen from only non-emitting resources such as intermittent and nuclear (but negative pricing is not necessarily problematic if it induces less unit commitment from fossil plants); has implications for whether resources can produce a ZEC in hours when they were involuntarily curtailed
- Adjustments to Future Resource Ratings:
  - Generators that under-deliver in Year 1 will have resource qualification to offer in Year 2 (and subsequent years) reduced. Similarly, resources that over-deliver can have increased qualification in subsequent years

How does ISO create the demand curve for ZECs?

Answer: Details have to be worked out by stakeholders. CLF suggests the following criteria:

- Curve should be created by ISO based on demand specified by the states and their respective carbon goals
- Curve should start with carbon goals and work back to annual ZEC demand curve
- Curve should avoid year-over-year price volatility by increasing procurements annually
- Option for ZEC price and quantity points to come from each state (recognizing differentiated procurement goals), but likely would need some durability to the states' commitment to avoid regulatory uncertainty (e.g. each state submits a demand for ZECs, but that quantity cannot be reduced for 10 years)

Should ZEC-eligible resources be able to withhold supply from the capacity market and offer only in the ZEC market (to avoid PFP exposure)?

Answer: Need to adapt offer structure and mitigation procedures appropriately

- Apply current monitoring and mitigation principles to this new construct
- Incumbent capacity resources continue to have a must-offer obligation for capacity; ZEC-eligible resource may have a must-offer obligation if the auction is deemed structurally uncompetitive
- Appropriate formulas for offer caps will be developed, and may differ for ZEC-only, capacity-only, and ZEC+capacity clearing outcomes
- For example, a resource clearing for ZECs must still earn a sufficient additional payment to take on a capacity obligation and the associated PFP exposure (or lost bonus payments that would be available to a resource without a CSO)

Will ZECs that clear in the auction have any effect on NICR?

Answer: No

- Ex ante, the number of ZECs that ISO seeks to procure in an auction will not affect the ISO's NICR calculation
- When the auction is cleared, the ZECs that the ISO actually procures also will not count toward satisfying the NICR (however, the underlying resource that is selling ZECs will also have some capacity value, and so that capacity value will contribute toward meeting the NICR requirement)

Reason: Two different commodities (CSO and ZECs), calibrated in different units (MW for CSO; MWh for ZECs), with two different demand curves

Can ZEC-eligible resources offer into only the FCM-C market?

Answer: Yes, but subject to monitoring and mitigation provisions

- Typically, resources will want to sell both products to earn maximum revenues unless there are technical limitations
- But the products are decoupled and so need not be sold together (e.g. capacity can be sold into another market, while ZECs are sold into ISO New England)
- Monitoring and mitigation provisions will determine procedures for when and whether one of the products have a "must offer" requirement, likely the must offer requirement will be applicable to all existing resources qualified for each product unless they show a technical inability to deliver the product or an off-system commitment

Do states retain their ability to use PPAs?

Answer: Yes (but a functional FCM-C could limit the need)

- We anticipate that states may continue to use PPAs, for technology and location-specific procurements and as a supplement to FCM-C to pursue some policy objectives, e.g. if states desire that a subset of the total system ZECs come from a higher-cost resource type that would not otherwise clear the FCM-C, but that is desired for other reasons
- Revenues from any PPAs that are not broadly available might continue to be considered “out-of-market” but could be exempted from ORTP up to a renewables exemption limit

How do ZECs interact with RECs?

Answer: Two additive products

- There are several options for accounting, but we suggest one as a starting point
- ZECs reflect all non-emitting resources, RECs reflect a subset of the ZECs that also meet the additional requirements imposed under a state's RPS
- Thus, the ZEC reflects the "non-emitting" attribute, while the REC reflects any additional "state policy value" placed on a subset of these resources such as Class I renewables
- REC prices would drop to zero and be over-supplied if the least-cost resource for meeting ZECs is also qualified to produce RECs

APPENDIX

Details on Auction Clearing Examples

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Example 2 Detail: Wind is Marginal for ZECs
Gas CC is Marginal for Capacity

Resource Offers and Clearing Results

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Resource Ratings					
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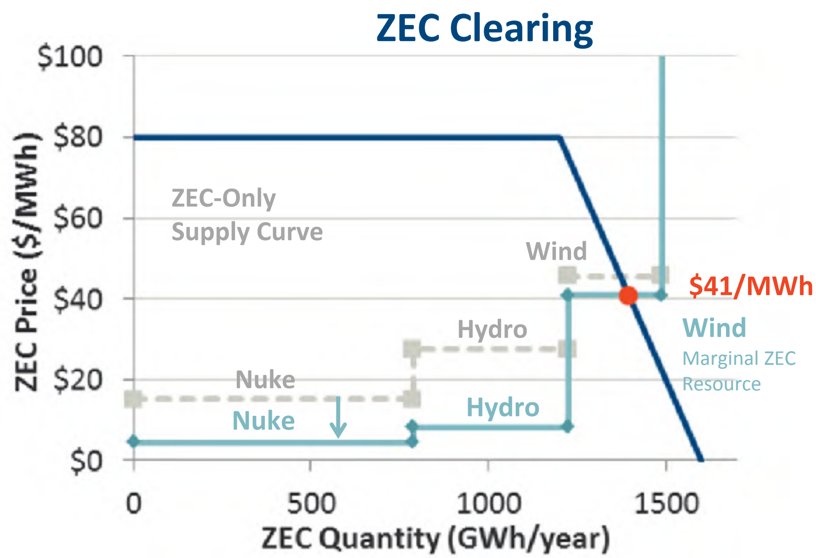
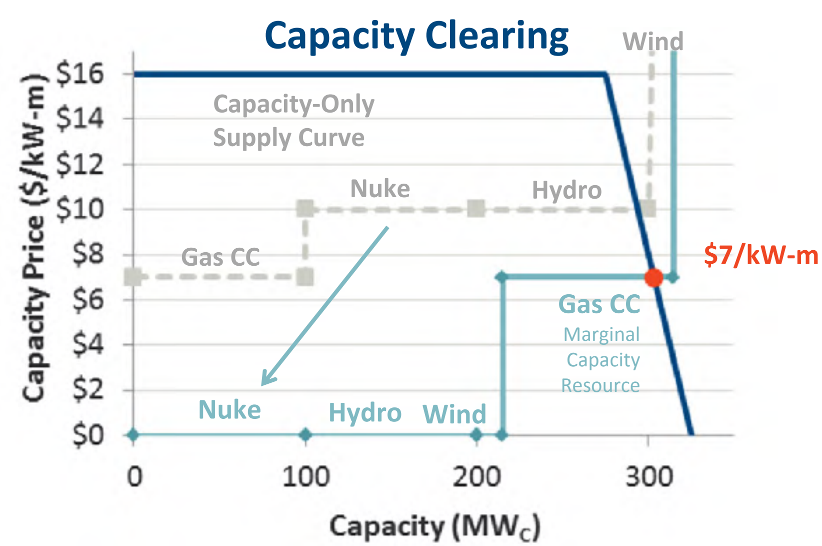
Capacity	*(MW_C)*	100	100	100	15
ZECs	*(GWh/year)*	788	438	0	263
Offer Price	*($/kW-m $_N$)*	$10	$10	$7	$10
Cleared Quantity					
Nameplate	*(MW_N)*	100	100	93	64
Capacity	*(MW_C)*	100	100	93	10
ZECs	*(GWh/year)*	788	438	0	169
Percent Cleared	*(%)*	100%	100%	93%	64%
Revenues					
ZECs	*($M/year)*	$32	$18	$0	$7
Capacity	*($M/year)*	$8	$8	$8	$1
Total	*($M/year)*	$41	$26	$8	$8
Total	*($/kW-m $_N$)*	$34	$22	$7	$10





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Notes: Supply curve for ZECs reflects minimum ZEC price that each resource is willing to accept, given the capacity clearing price. Similarly, supply curve for capacity reflects minimum capacity price each seller will accept once the ZEC price is known.

Example 3 Detail: Nuclear Plant is Marginal for Both Products

Resource Offers and Clearing Results

		Nuke	Gas CC A	Gas CC B	Wind
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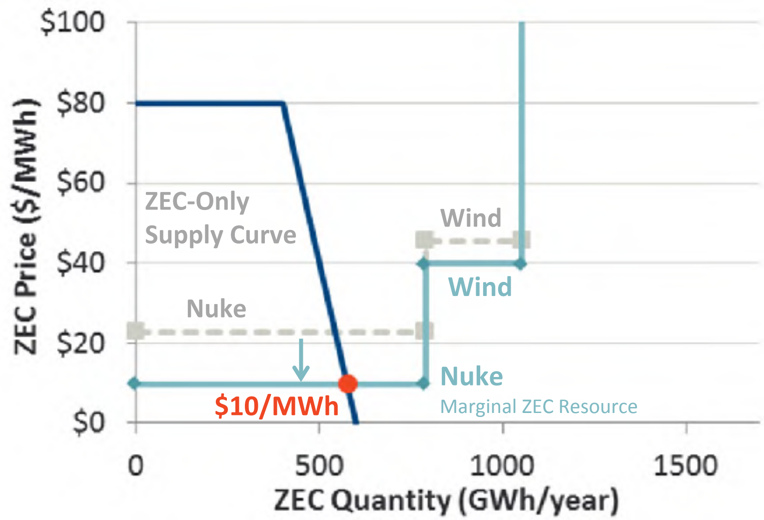
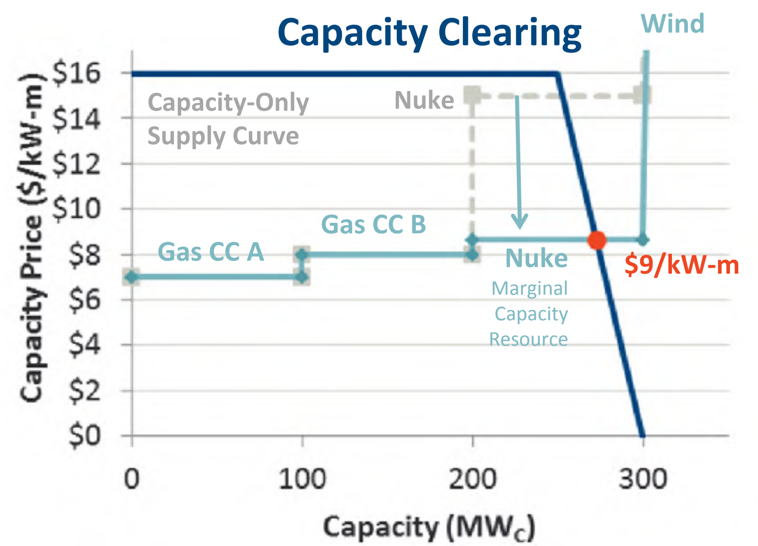
Capacity	*(MW_C)*	100	100	100	15
ZECs	*(GWh/year)*	788	0	0	263
Offer Price	*($\$/kW\text{-}m_N$)*	$15	$7	$8	$10
Cleared Quantity					
Nameplate	*(MW_N)*	73	100	100	0
Capacity	*(MW_C)*	73	100	100	0
ZECs	*(GWh/year)*	576	0	0	0
Percent Cleared	*(%)*	73%	100%	100%	0%
Revenues					
ZECs	*($M/year)*	$6	$0	$0	$0
Capacity	*($M/year)*	$8	$10	$10	$0
Total	*($M/year)*	$13	$10	$10	$0
Total	*($\$/kW\text{-}m_N$)*	$15	$9	$9	$0

ZEC Clearing



Capacity Clearing



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Perspectives on IMAPP and Demand Response

October 21, 2016

IMAPP: Where are we headed and why should we care?

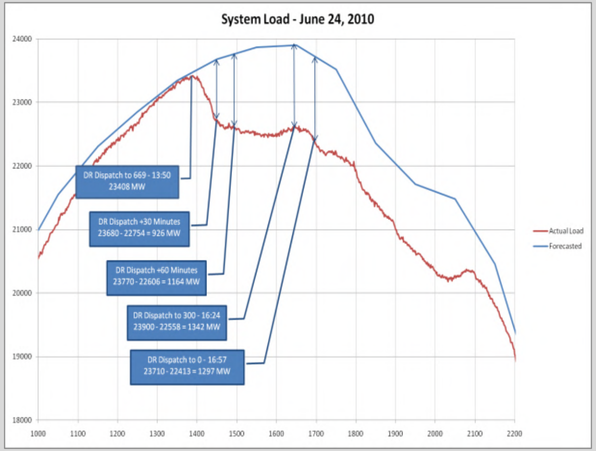
- Region's high dependence on natural gas and increasing penetration of renewables underscores the need for <u>fast</u> and <u>flexible</u> capacity resources. Lynchpins behind "Pay for Performance:"
  - *"Many of these challenges could be resolved if suppliers undertook additional operational-related investments, whether in dual-fuel capabilities, short-notice and/or non-interruptible gas supply agreements, **new fast-responding demand response assets**…" (ISO-NE Pay for Performance White Paper)*

- DR/DER that provides reserves not only facilitates the integration of renewables but <u>reduces carbon emissions</u>
  - *"Overall Navigant estimates that DR can directly reduce CO2 emissions by more than 1 percent through peak load reductions and provision of ancillary services, and that it can indirectly reduce CO2 emissions by more than 1 percent through accelerating changes in the fuel mix and increasing renewable penetration." (Navigant, AEMA, 2014)*

IMAPP: The risks of unintended consequences

- To avoid unintended consequences that these fast, flexible resources are no longer incented to participate in wholesale markets, IMAPP process needs to better consider:
  - Clean resources that do not depend on energy market/PPA revenues
  - Impact of proposals on capacity market prices

DR: Attributes of the Resource



- Flexible system resource:
  - Highly reliable
  - Fast-responding (≤30 minutes)
  - Dispatched at sub-load zone level, and highly distributed nature mitigates non-performance risk
- Clean resource for region
- Dependent on competitive wholesale markets for deployment in region
  - Does not receive out of market payments

➔IMAPP should preserve and strengthen the role of DR in New England

Demand Response's Role in ISO-NE: Past, Present, and Future

- Under past and current market design and rules, DR was/ is an emergency product

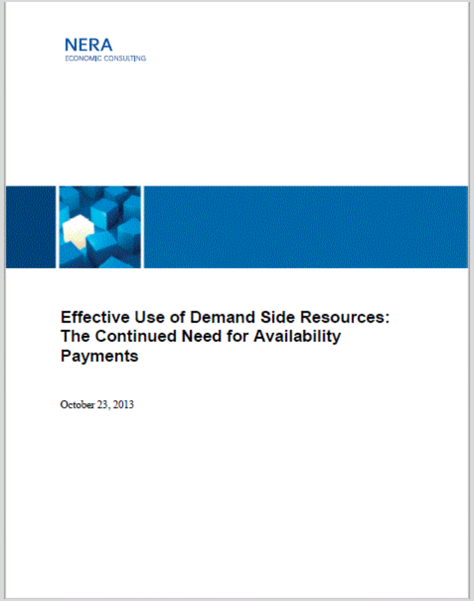
- In 2018 under Pay-for-Performance (PfP), DR is an economic/reserve product
  - Will be fully integrated into the co-optimized energy and reserves market - perform in ≤ 30 minutes
  - Will deliver "negawatt hours" when dispatched, and clean reserves when not dispatched
  - Will continue to have high opportunity costs for customers to reduce consumption

➔ ***DR with a CSO will be well-utilized as a reserve resource beginning in 2018 but will not receive significant revenues from the energy market***

A Competitive Capacity Market is Essential to DR and other Customer-Sited Resources

- As documented in academic literature, capacity payments are foundational to DR participation and to end-use customer participation.
  - Same may be true for other innovative technologies (DER)
- A competitive capacity price signal is foundational for DR and reserves does not happen without it
- FCM reduces the speculative nature of investment, and an uncompetitive FCM price will dampen enthusiasm for new technologies

➔ ***Capacity markets play a unique role specific to Demand Resources that is different from Generation resources***



IMAPP Proposal Implications

- Multiple proposals attempt to create a new market design to achieve public policy goals by fundamentally changing what capacity market design and revenues are intended to compensate
  - The FCEM and carbon price proposals significantly increase the role of energy market payments
  - To extent that energy revenues seek to cover capital as well as operating costs of projects, and those energy revenues are considered “in market” for purposes of the FCM, capacity pricing will be impacted
- The two-tiered pricing proposal seeks to accommodate public policy deployment while maintaining a competitive capacity market

Considerations for IMAPP Process Going Forward

To preserve and grow DR/DER participation in ISO-NE, IMAPP solutions need to:

- Preserve a competitive capacity market
  - Any proposal should describe its impacts on capacity market, specifically re price suppression
- If “clean” technologies are brought to market via an energy market, enable a level playing field for demand response
  - FCEM proposal should be amended to include a revenue opportunity for clean resources providing reserves
  - Provides a revenue stream to maintain the competitive positioning of these clean resources relative to those resources included under umbrella of public policy incentives

NEPOOL IMAPP Stakeholder Discussion October 21, 2016

Capacity markets & efficient renewable procurement in a carbon-constrained world:

Near-term vs. Long-term

Pete Fuller

Today's Discussion

- ✓ **IMAPP Objectives –** States and market participants
- ✓ **'Accommodate' vs. 'Achieve' –** Existing state policy requirements vs. anticipated policy objectives
- ✓ **Two-tier Pricing as a Critical Near-term Step** – maintains price signals and revenue for existing and needed new conventional resources during market transition.

IMAPP Objectives

- ✓ **States' Objective 1**: Accommodate states' near-term procurement mandates in wholesale markets with existing or revised market rules, to maintain reliability at least cost.
  - ✓States will be proceeding with mandated contracting processes
  - ✓According to the States, the existing renewable technology resource (RTR) exemption 'reasonably accommodates' state objectives

- ✓ IMAPP Status:
  - ✓Two-tier pricing proposal enables all state policy resources to participate in FCM and avoids 'double-payment' for centrally-procured (FCM) and state-procured capacity
  - ✓NRG proposal for two-tier also respects Wholesale Suppliers' Objective 1 (below), while RTR exemption and Public Systems' proposals do not

IMAPP Objectives

- ✓ **States' Objective 2**: Implement an ISO-NE administered auction framework for state-mandated policy requirements.
  - ✓Provide flexibility for states to specify, e.g., quantity, technology, location
  - ✓Additional design specs: i) revenues should be considered 'in market' for FCM mitigation purposes; ii) states control purchase requirements; iii) enable comparison of alternatives needing transmission or not
- ✓ IMAPP Status:
  - ✓Broad interest in FCEM/FCM-C concept, with many details yet to be worked out; this will take time
  - ✓Incorporating all of the states' criteria could lead to a 'Swiss Army Knife' design to accommodate <u>any</u> future state policy; may not work particularly well for any of them
  - ✓In-market vs. out-of-market treatment of revenues cannot be decided *a priori*

IMAPP Objectives

- ✓ **States' Objective 3**: Implement a 'need-based' mechanism in the ISO-NE markets to enable states to retain existing resources for policy purposes.

- ✓ IMAPP Status:
  - ✓A carbon adder in the energy dispatch could likely address revenue challenges for existing desired resources, but is not necessarily need-based nor easily adjustable over time
  - ✓A targeted, contract-based approach to retaining existing resources could be accommodated in a two-tier pricing mechanism with appropriate extension of MOPR to Existing Resources

IMAPP Objectives

- ✓ **Wholesale Suppliers' Objective 1**: Support and accommodate states' policy objectives without bearing the full cost of them through wholesale market price suppression
  - ✓Just as states insist that policy mandates of one state not impose costs on consumers in another state, state policies should not impose undue burdens on investors relying on FERC-jurisdictional markets.
  - ✓Wholesale markets are the basis for building and maintaining reliability infrastructure, and need to be free of distortion from entry and exit driven by non-market/non-economic factors

- ✓ IMAPP Status:
  - ✓NRG's two-tier pricing proposal is the only solution proposed to date that directly addresses this objective

‘Accommodate’ vs. ‘Achieve’

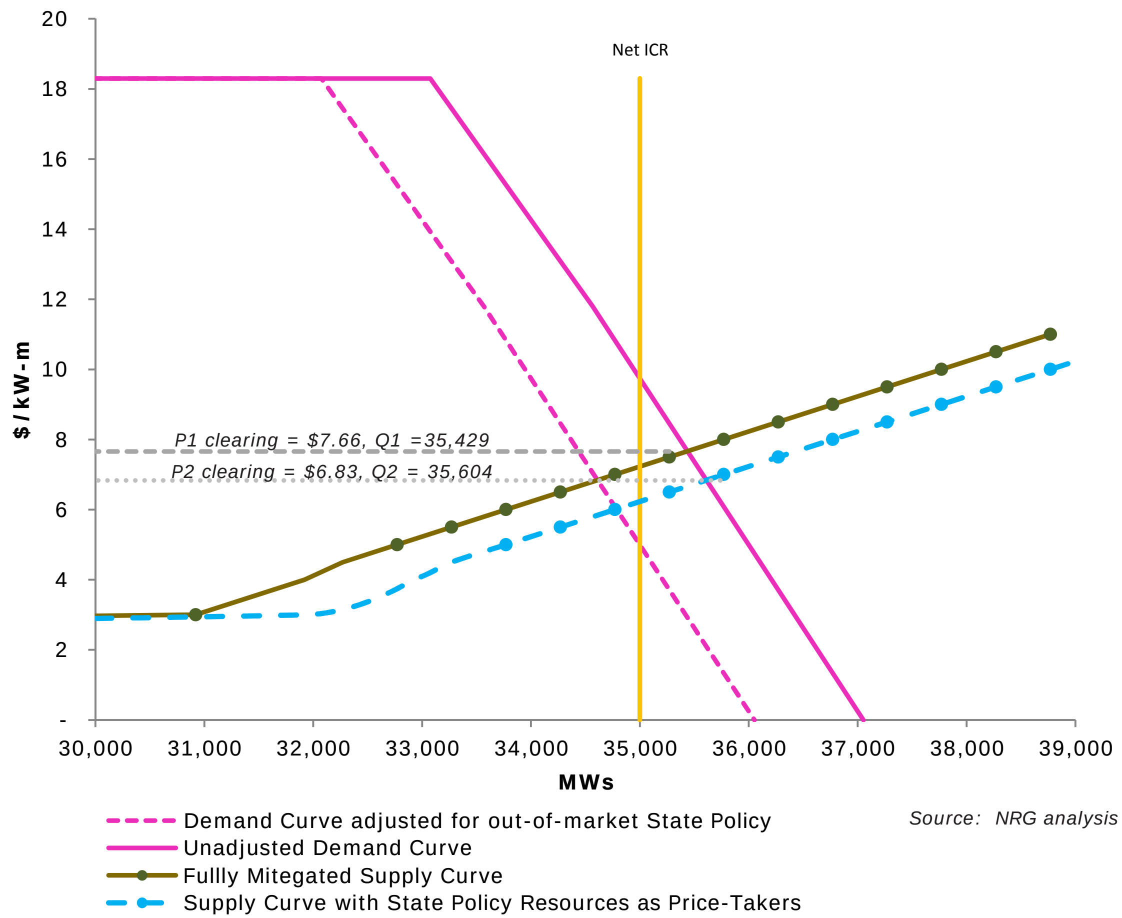
- ✓ There are existing resources with state-backed contracts pursuant to state policy objectives
- ✓ States have existing statutory requirements to secure additional resources to meet policy objectives
- ✓ The ISO-NE markets must *accommodate* these existing resources and laws while maintaining the integrity of price formation and investment incentives
- ✓ The long-term objective should be to obviate the need for future statutes by enabling the markets to *achieve* a low-carbon, sustainable fleet for the future

To the extent states establish policy goals not met through carbon/renewable attributes that can be integrated into the markets, those can be accommodated through two-tier pricing

The near-term issue – FCM Price Formation

- ✓ With full application of mitigation, i.e., all resources offering at a competitive level (green supply curve), the clearing price in this example is **$7.66 / kW-mo**, and the cleared quantity is 35,429MW.
    - o The total market cost is $7.66/kW-mo x 35,429MW = **$3,257 million**
- ✓ With 1,000MW of State Policy (SP) Qualified Capacity inserted as price-takers (blue supply curve), the clearing price is **$6.83 / kW-mo**, and the cleared quantity is 35,604MW
    - o The total (market) using the blue curve would be $6.83/kW-mo x 35,604MW = **$2,918 million**
    - o This is the price-suppression effect of out-of-market capacity
- ✓ Adjusting the market demand (dotted pink demand curve) leads to similar price suppression. Clearing with the green supply stack, the clearing price would be **$6.83 / kW-mo**, and the cleared quantity would be 34,604MW
    - o The total market cost is $6.83/kW-mo x 34,604MW = **$2,838 million**

Illustrative FCM auction pricing



Source: NRG analysis

The Near-term Challenge

- ✓ States are moving ahead with additional policy-based procurements
- ✓ FCM, and the ISO-NE markets overall, need to maintain the integrity of price formation to support efficient merchant entry and exit
- ✓ NRG's two-tier pricing mechanism:
  - ✓ Enables <u>all</u> state policy resources to access FCM compensation
  - ✓ Maintains marginal price signals for private investment decisions
  - ✓ Does not impose the full cost of state policies on capacity suppliers
- ✓ Two-tier pricing should be pursued even as the region works to develop a market design to *achieve* a low-carbon, sustainable fleet for the future

Questions?

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A GENERATION AHEAD,
today

Integrating Markets And Public Policy

Brett Kruse
CALPINE CORPORATION

October 8, 2016

CLEAN MODERN EFFICIENT FLEXIBLE POWER GENERATION

Near-term Future Absent Change

- Current market rules include MOPR protection along with limited exemption for new renewables.

- Existing and upcoming state RFPs are likely to procure several thousand MWs of new zero carbon resources

- Many will fail MOPR, while some may be eligible for the RTR Exemption

- These initiatives will undeniably have an adverse impact on wholesale electricity markets; market participants will have no choice but to challenge them through litigation at FERC and in the courts.

Creating a Structure That Allows Markets and State Intervention To Peacefully Coexist Requires Capacity Market Protection For Existing Resources

- Capacity Market Protection:
  - NRG has proposed an "alternative price rule" approach
  - PJM has proposed a similar idea to their stakeholders
  - While details need to be worked out, these proposals are thoughtful, viable ideas that could provide some level of "price formation" protection in the face of state intervention

In exchange for Capacity Market Protection, states will potentially gain the following:

- Rules that allow for implementation of state policies that could impact the wholesale competitive market, including:
  - Elimination of the MOPR
  - Elimination of the RTR exemption
- If desired, although unnecessary, can also add a carbon dispatch component

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NYSE CPN

New England States
Committee on Electricity

To: NEPOOL
From: NESCOE
Date: October 18, 2016
Subject: Some Analysis on Two-Tiered Pricing Proposals

NESCOE appreciates the work that market participants have done to develop and advance proposals in the Integrating Markets and Public Policy (IMAPP) process.

As we have noted during IMAPP meetings to date, we are assessing proposals and their elements. To assist consideration of several two-tier pricing proposals, we asked Wilson Energy Economics to provide a critique. We share information here with NEPOOL to add to the body of information available to all participants evaluating the various proposals. We welcome feedback, constructively critical or otherwise, on the substance of the memo from two-tier pricing proponents or any other entity.

There are multiple two-tiered pricing proposals in the IMAPP process at this time. They are not identical. This memo does not suggest and should not be interpreted to mean that the two-tiered proposals are the same or would have the same market or consumer implications aside from the issue specifically discussed in the memo.

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TO: NESCOE

FROM: James F. Wilson, Wilson Energy Economics

SUBJECT: **IMAPP "Two-Tier" FCM Pricing Proposals: Description and Critique**

This memo provides a summary and critique of the proposals for "two-tier" pricing in ISO New England's Forward Capacity Market ("FCM") that have been put forward in the NEPOOL IMAPP process.

I. The Problem

Proposals for two-tiered pricing in the FCM (described in detail below) arise from concerns around the potential impact of state-funded resources (such as result from state renewable resource procurements for energy and capacity) on FCM clearing prices: if these resources are permitted to offer into FCM at lower prices reflecting the state funding, this raises a concern that FCM clearing prices will be "suppressed" below the competitive levels needed to attract sufficient new entry and to properly compensate existing resources. But if, on the other hand, the state-funded resources are mitigated and, as a result, fail to clear in the FCA and do not receive Capacity Supply Obligations ("CSOs"), consumers will be forced to pay twice for capacity (once through retail rates that recover the costs of the state-funded resources, and again through FCM for duplicative capacity resources cleared as a result of the mitigation of the state-funded resources). For the purposes of this memo, resources that are subject to offer price mitigation in the FCM (because they are state funded, or have other contractual arrangements or sources of revenue; this may include some self-supply resources) are referred to as Subject To Mitigation ("STM") resources.

The presence of STM resources in the FCM creates a conflict between three competing capacity market design objectives:

1. recognizing the contribution of the STM resources to resource adequacy by granting them CSOs;
2. establishing a "competitive" FCM price for compensating existing and attracting new non-STM resources, that is not suppressed by the offers of STM resources; and
3. clearing a reasonable total amount of capacity at a reasonable total cost.

Proposals involving two-tiered FCM pricing are one approach to partially reconciling the conflict between these objectives.

Also note that this problem will likely still be present even if the IMAAP process results in a Forward Clean Energy Market or other market design changes, due to legacy contracts for renewable resources.

II. Some History of Two-Tiered Capacity Market Pricing Proposals

Recall that in 2010 the ISO had proposed a two-tiered pricing approach in a proceeding pertaining to its "Alternative Price Rule" (ER10-787, EL10-50), and the Joint Filing Supporters, with my affidavit attached, were critical of the proposal at that time (link). FERC rejected the proposal because it would have cleared a quantity of capacity in excess of the Net Installed Capacity Requirement ("NICR"), thereby violating what it referred to as a "bedrock principle" of the New England capacity market at the time, which used a vertical demand curve (link at P 164). Some parties have expressed the view that because FCM now uses a sloped demand curve, the "bedrock principle" of not clearing more than NICR has been removed, which could open the way for FERC approval of a two-tiered pricing proposal.

At present, minimum offer price mitigation is applied in FCM, along with a limited exemption for certain resources. This compromise is working for now, however, more renewable resource procurements are underway, so the conflict between the three competing objectives listed above is likely to again become problematic.

Very recently, PJM proposed a two-tier pricing proposal for its capacity construct, in the context of a "Grid 2020" meeting with a similar scope to the IMAPP effort (link). I am not aware of any market in which a two-tiered capacity pricing proposal has actually been implemented.

III. IMAPP Two-Tiered Pricing Proposals: The Public Power Proposal

Two proposals for two-tiered FCM pricing have been put forward in the IMAPP process; an original (link) and updated proposal (link) by NRG, and an alternate proposal by Public Power (link). While the NRG proposal was floated first, this memo will first describe and critique the Public Power proposal, which is more straightforward and similar to the PJM proposal noted above. The NRG proposal, which has provisions that attempt to address some of the shortcomings of the PJM and Public Power proposals, will be discussed second.

A. Description of the Public Power proposal

The basic idea of two-tiered pricing, which is reflected in the Public Power proposal, is as follows. The FCM Forward Capacity Auction ("FCA") is run twice, in two "stages." In what this memo will call Stage 1, STM resources are not mitigated, so presumably they are offered at low prices and "clear" the auction (meaning, are chosen to receive a CSO). Call the resulting Stage 1 clearing price and quantity P1, Q1. Then in Stage 2, the STM resources (identified in more detail below) are mitigated (ORTPs), but all other resources' offers are unchanged, so presumably the supply curve shifts to the left. This will in general result in some of the mitigated resources no longer clearing, causing a higher clearing price and lower cleared quantity in Stage 2. Call the resulting Stage 2 clearing price and quantity P2, Q2 (see the two figures below, discussed in the context of an example).

All resources that cleared in Stage 1 (Q1 MW), including any STM resources that cleared, will get CSOs. However, all allegedly "competitive" (non-STM) resources that cleared in Stage 1 will be paid not P1, but the higher Stage 2 price, P2. The STM resources that cleared in Stage 1 but not in Stage 2 will be paid the lower Stage 1 price, P1.

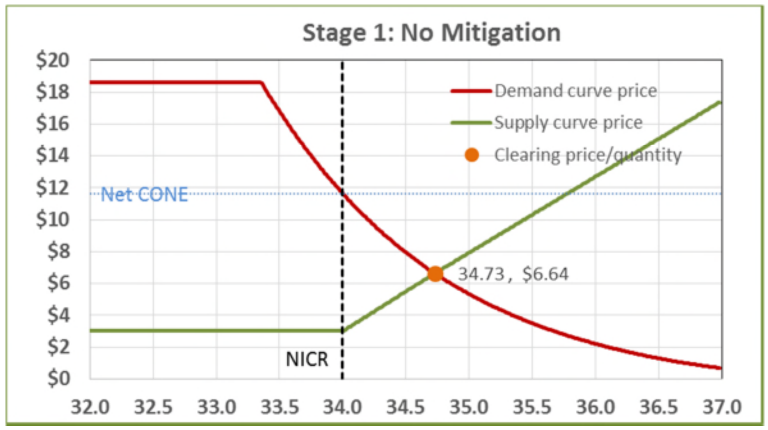
Under any two-tiered pricing proposal, the issue arises of what to do about so-called "in between" or "tweener" resources: those that offered at prices below the allegedly "competitive" Stage 2 clearing price P2, and so are apparently economic and deserving of a CSO, but offered above the Stage 1 clearing price, and so are not part of the Stage 1 cleared quantity, Q1. Under the Public Power (or PJM) proposal, the tweener resources do not clear and do not receive CSOs (treatment of the tweeners is significantly different under the NRG proposal discussed later in this memo). There are various other details of this (or any) two-tier pricing proposal, of which a few are noted later in this memo.

This approach addresses the three-way conflict identified above in the following way:

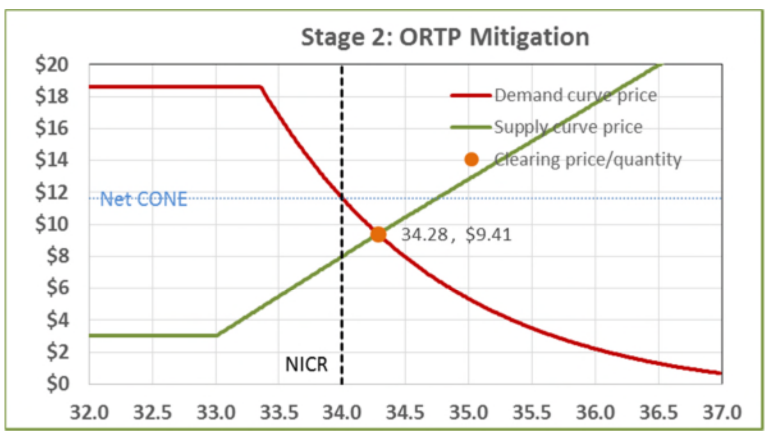
- ✓ STM resources get CSOs; and
- ✓ non-STM resources (at least those that cleared in Stage 1) get an allegedly "competitive" price P2 based on mitigation; while
- ✓ there is some compromise of the reasonable quantity/cost objective (discussed further below).

Before critiquing this proposal, consider a numerical example.

The first graphic shows an example in which Stage 1 sets a clearing price of $6.64/kw-mo and clears 34.73 GW (P1, Q1). Stage 1 determines which resources will clear and get a CSO: 34.73 GW, including the STM resources.



Then Stage 2 is run, in which STM resources are mitigated based on the ORTP prices. Suppose for purposes of the example there is 1,000 MW of STM resource, and when mitigated in Stage 2 it does not clear, essentially shifting the relevant section of the supply curve to the left by 1,000 MW. This is shown in the second graphic. Stage 2 results in a clearing price of $9.41/kw-mo (P2).



So in the example, all competitive (non-STM) resources that cleared in Stage 1 (the 34.73 GW minus 1 GW of STM resource = 33.73 GW) will get CSOs and be paid the higher, Stage 2 price of $9.41/kw-mo. The 1 GW of STM resource that cleared in Stage 1 will also get a CSO, but will be paid the lower, Stage 1 price of $6.64/kw-mo. The "tweener" non-STM resources that offered above $6.64/kw-mo but below $9.41/kw-mo will not get CSOs. In the example, there are .55 GW of tweeners (34.28 GW cleared in Stage 2, minus 33.73 GW competitive resources cleared in Stage 1).

B. Critique of the Public Power proposal

While addressing the three competing objectives to some extent, as noted above, the two-tiered pricing approach as put forward by Public Power raises the following three problems.

1. FCA cleared quantity and (average) price, and resulting total cost, are off the demand curve

Under the Public Power proposal the total cleared quantity is Q1, while most resources are paid P2 and only some STM resources are paid P1. In the example shown above, the average price paid is $9.33/kw-mo while the total cleared quantity is Q1, 34.73 GW. Treated as a price/quantity pair, this is a point that lies well above the stakeholder-agreed and FERC-approved sloped demand curve, as shown in this figure. Put another way, this FCA outcome results in a total cost that is in excess of what the demand curve suggests should be paid for the actual cleared quantity Q1, as summarized in this table.

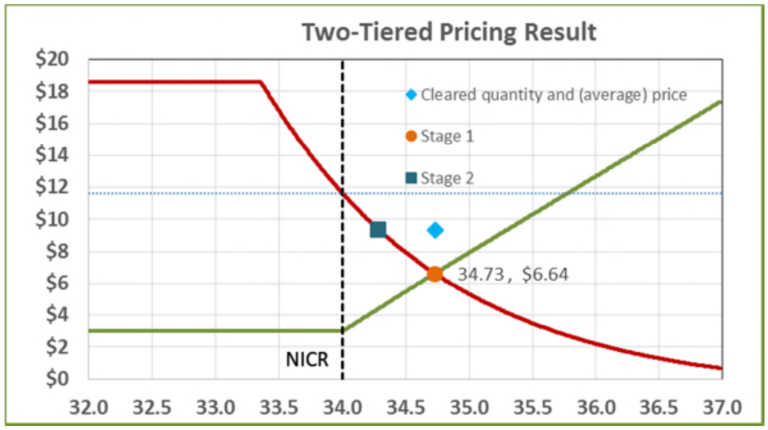


Table 1: Summary of Two-Tiered Pricing Example (Public Power Proposal)			
	Price	Quantity	Total Cost ($ bil.) [1]
Stage 1 (unmitigated) result	$ 6.64	34.73	$ 2.77
Stage 2 (mitigated) result	$ 9.41	34.28	$ 3.87
“Competitive” resources outcome	$ 9.41	33.73	$ 3.81
STM resources outcome	$ 6.64	1.00	$ 0.08
Average price, total quantity/cost	$ 9.33	34.73	$ 3.89
[1] For Stage 1 and Stage 2, total cost shown is simply price x quantity x 12 months, as if the stage determined the entire FCA result.			

In 2010 FERC was concerned that the two-tiered proposal cleared a total quantity in excess of NICR and this violated a “bedrock principle” of the FCM construct, as noted above. The Public Power two-tiered pricing proposal results in a cleared quantity and (average) price that lies above the agreed sloped capacity demand curve, which seems to violate the same principle, as applied to a sloped demand curve. The demand curve associates a price of $6.64/kw-mo, and a total cost of $2.77 billion, with the total cleared quantity of 34.73 GW, as shown in the table, while the total cost under the two-tiered approach would be $3.89 billion, over a billion dollars higher.

Note that in this example, the resulting total capacity cost, $3.89 billion, is actually quite close to the total capacity cost under the fully mitigated Stage 2 result, which as a stand-alone FCA outcome would result in a price of $9.41/kw-mo and total cost of $3.87 billion. However, this comparison ignores the loss of

$0.08 billion in capacity revenue to the STM resources, which would have to be recovered from consumers in another manner.

2. *Incentives to submit competitive offers are distorted*

The second concern is that the Public Power two-tiered pricing proposal distorts resources' choices with regard to offer prices.

Under the current FCA structure (or the structure of just about any auction), in principle, a resource's offer into the auction should be the price the resource requires in order to want to clear in the auction. That is, the resource's FCA offer price should be the price needed to make taking on a CSO worthwhile. If the FCA clears at a price above a resource's offer price, it clears and gets a CSO, and is satisfied with this result because the price is enough (likely more than enough) to make taking on the CSO worthwhile. If the FCA clears at a price below the resource's offer price, the resource does not receive a CSO and is again satisfied with this result, because at that clearing price it doesn't want a CSO. An owner might determine the price a resource "needs" to make a CSO worthwhile based on its avoided cost, or an opportunity cost concept, or some other analysis, it doesn't matter; if the auction is well-structured, the incentive is to make an offer based on the price considered needed (setting aside market power considerations). For the purposes of this memo, this will be referred to as the resource's "cost-based" offer price, recognizing that this may be an opportunity cost.

However, under the Public Power (or PJM) two-tier pricing proposal things are different. Under this proposal, the resource will get a CSO and be paid P2 if it clears according to the Stage 1 clearing price P1. In our example above, if the resource offers at less than or equal to $6.64/kw-mo (the Stage 1 price) it clears, and will be paid $9.41/kw-mo (the Stage 2 price).

Now suppose the resource's cost-based offer price is, say, $7/kw-mo. If it offers at this price, it will not clear in Stage 1, and will not receive anything. But the Stage 2 price (that it won't get, because it didn't clear in Stage 1) is well above the price it needs. So if the owner suspects that Stage 1 may clear in the $6 to $7/kw-mo range, and Stage 2 might clear well above $7 (as in the example), the owner might rationally choose to offer at $6/kw-mo, even though that is below the price it needs. With this strategy the resource will clear in Stage 1 and get paid the higher Stage 2 clearing price. This strategy is more profitable than the initial approach of offering at $7/kw-mo (the cost-based offer) and failing to clear.

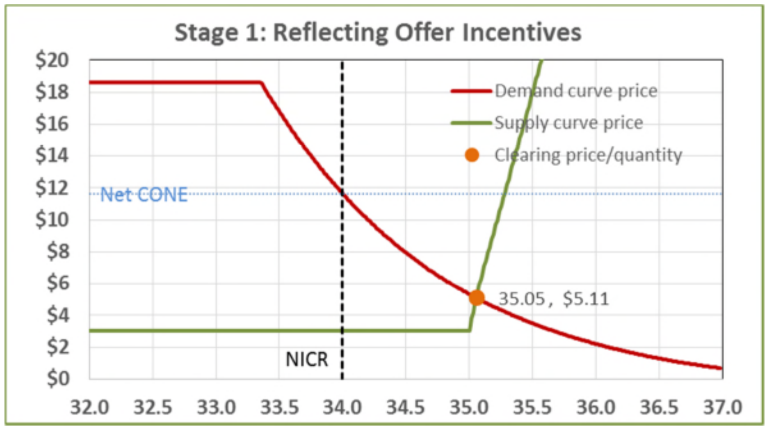
So to the extent the FCA Stage 1 price is reasonably predictable, resources whose cost-based offers are close to the expected Stage 1 clearing price have incentives to shave their prices and offer somewhat lower to increase their chances of clearing in Stage 1. This has been called by some a "race to the bottom." To the extent this occurs, Stage 1 will clear a larger Q1 quantity, at a now lower P1 price, than if all resources submitted cost-based offers.

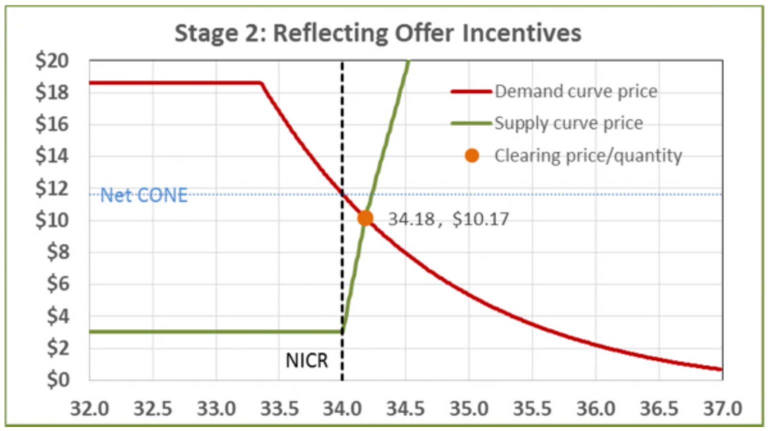
It could be argued that this incentive problem may be unimportant because FCA clearing prices are not very predictable. While this may be true to some extent, especially in the near term, market designs should be robust and workable from a long-run, equilibrium point of view. If the FCA rules are reasonably stable over time, clearing prices should become rather predictable. It could also be argued that this incentive problem is not important if P1 and P2 are not very different, as would be the case if mitigation does not shift the supply curve very much. This is true, but the market design should be robust under circumstances where the quantities of STM resources may be larger. As the numerical example shows, if 1,000 MW is mitigated such that it fails to clear in Stage 2, this can drive a substantial wedge between the Stage 1 and Stage 2 prices.

The "race to the bottom" is one bad incentive created by the two-tiered pricing proposal. There is a second one. Now consider a resource whose cost-based offer price is around $8/kw-mo. Suppose the owner considers it too risky to shave the offer price enough to clear in Stage 1 (down to the $6 to $7/kw-mo range), so the owner won't join the race to the bottom, that he would likely lose. So does he still offer the resource at $8/kw-mo? If the owner accepts that the resource won't clear in Stage 1 and won't receive a CSO, what difference does the offer price make?

The offer price won't determine whether the resource will clear (it won't clear), but the offer price <u>will</u> affect the Stage 2 clearing price. Suppose the owner anticipates that Stage 2 will likely clear at a price in the $8 to $10/kw-mo range, <u>above</u> his cost-based $8/kw-mo offer price. Then if he instead offers at, say $10/kw-mo, Stage 2 might clear at a somewhat higher price than it otherwise would have. If the owner has only the one resource, this still makes no difference to the owner. But if the owner has any other capacity that will clear in the auction, then it will increase profits to offer this resource not at its cost-based $8/kw-mo price, but at a higher price, in order to support a higher Stage 2 clearing price that will be earned by the rest of the owner's portfolio.

To summarize, resources with costs expected to be close to the Stage 1 clearing price have an incentive to shave their offer prices to increase their chances of clearing in Stage 1, while resources that do not have much hope to clear in Stage 1 may have an incentive to offer at high prices to contribute to a higher Stage 2 clearing price. The result is that, compared to cost-based offer prices reflecting what a resource needs, Q1 is likely to be larger (due to the first incentive) and P2 is likely to be higher (due to the second incentive) further raising the quantity, price, and cost of capacity.





Returning to the numerical example, suppose these incentives change the supply curve as shown in the next pair of figures, reflecting some resources offering at lower prices to attempt to clear in Stage 1, and other resources offering at higher prices to support a higher Stage 2 price, resulting in a steeper supply curve. The example suggests that Stage 1 would now clear 35 GW at $5.11/kw-mo, while Stage 2 would clear at $10.17/kw-mo. The larger cleared quantity and higher P2 price would of course increase capacity cost compared to the outcomes under bidding not influenced by these incentives.

As a general matter, any proposal under which <u>who</u> clears is determined by one price threshold, while <u>what</u> price the cleared resources actually get paid is substantially different, will create incentive issues.

3. The rate P2 is established arbitrarily

A third problem with this two-tiered proposal focuses on formation of the Stage 2 price P2 paid to all but STM resources. Assuming the Stage 1 and Stage 2 prices, P1 and P2, are substantially different, as in the numerical example, the P2 clearing price would likely be set by an offer from a resource whose owner knew it would not clear and would not receive a CSO. Accordingly, the P2 price, which becomes a rate upon which over a billion dollars in capacity payments will be based, is rather arbitrary, as it is set by offers from resources that don't have anything at stake in selecting their offer prices (except for the incentive, described above, to inflate the offer price to support a higher P2 clearing price, which only makes things worse). Furthermore, the P2 price formation also reflects the administrative mitigation of STM resources, which likely results in resources that already exist being treated for price formation purposes as if they do not exist. FERC may find this proposed basis for setting the P2 rate unacceptably arbitrary.

Finally, I note that in my 2010 affidavit in the APR proceeding I raised additional issues with the two-tier pricing concept, of which some are applicable to this proposal (summary on p. 36 of the affidavit, which was linked above).

IV. IMAPP Two-Tiered Pricing Proposals: The NRG Proposal

A. Description of the NRG proposal

The Public Power (and PJM) two-tier pricing proposals leave out the tweener resources with offer prices between the Stage 1 and Stage 2 clearing prices – the tweeners do not get CSOs. To the extent it is accepted that the P2 price is the "right", competitive price, these resources are economic, so leaving them without CSOs seems unfair to those resource owners. And, as described above, this also gives the lower-cost tweener resources incentives to shave their offer prices to try to clear in Stage 1, and the higher-cost tweener resources incentives to inflate their offers to support a higher P2 clearing price.

The NRG proposal attempts to address these problems. (This description of the NRG proposal, for consistency, will use the nomenclature of the PJM and Public Power proposals, which is different from NRG's document; in this memo, Stage 1 is the unmitigated stage, and Q1 and Q2 refer to the total quantity cleared in each stage).

The NRG two-tiered pricing proposal is the same as the Public Power proposal, with the following principal differences:

1. The "tweener" resources that offered below P2 in Stage 2 also clear and will receive CSOs, but
2. All resources' cleared quantities are reduced on a pro-rata basis such that the total market capacity cost is held equal to the Stage 2 total cost (P2 x Q2).

Specifically, all resources' CSO quantities are reduced by the ratio of the total capacity cost, based on the nominal Stage 1 and Stage 2 outcomes, to the total capacity cost based solely on the Stage 2 outcome. Under the nomenclature of this memo, the ratio for reducing CSOs is (P2 x Q2)/(P2 x Q2 + P1 x Qs), where Qs is the quantity of STM resource that clears in Stage 1 but not Stage 2 (1 GW, in the example above).

Table 2 summarizes the result of the previous example, under the NRG proposal. Under these assumptions, the total capacity cost and average price happen to be very close to their values under the Public Power proposal; the main differences are that, under the NRG proposal, 1) the tweeners also get CSOs, and 2) all CSO quantities are reduced by 2%.

Table 2: Summary of Two-Tiered Pricing Example (NRG Proposal)

	Price	Quantity	Total Cost ($ bil.) [1]
Stage 1 (unmitigated) result	$ 6.64	34.73	$ 2.77
Stage 2 (mitigated) result	$ 9.41	34.28	$ 3.87
Total Capacity Cost (Stage 2 result)			$ 3.87
Cost, including STM resources			$ 3.95
Ratio for reducing CSOs			98.0%
"Competitive" resources outcome	$ 9.41	34.28 x 98%	$ 3.79
STM resources outcome	$ 6.64	1.00 x 98%	$ 0.08
Average price, total quantity/cost	$ 9.33	34.57	$ 3.87

[1] For Stage 1 and Stage 2, total cost shown is simply price x quantity x 12 months, as if the stage determined the entire FCA result.

B. Critique of the NRG proposal

This critique follows the issues raised around the Public Power proposal.

1. FCA cleared quantity and (average) price, and resulting total cost

The NRG proposal clears the tweener resources, and then scales CSO quantities in order to hold the total market cost to the cost based on the price and cleared quantity from Stage 2. The scaling of CSO quantities is of course a drawback of the approach; no resources are held harmless due to the presence of STM resources, as all resources, including competitive and self-supply resources, receive reduced CSOs under this proposal.

Under the numerical example shown above, the resulting total cleared quantity, average price, and average cost with the NRG approach are very close to the results under the Public Power proposal (before considering impacts due to the incentive effects of the Public Power proposal). The price, quantity and cost outcomes are slightly different but still above the demand curve, as under the Public Power proposal. The differences between the two proposals (before considering incentive effects) could of course be larger if the quantity of STM resource is larger, or if a different region of the demand curve is implicated.

2. Incentives to submit competitive offers

Under the NRG proposal, resources clear and get a CSO as long as they offer at less than the P2 price; and if clearing, they are paid the P2 price. Therefore, this proposal repairs the incentive problems created by the Public Power and PJM two-tier pricing proposals under which the price determining whether a resource clears, and the price that will be paid, can be significantly different.

On the other hand, because CSO quantities are reduced pro-rata, resource owners that need a certain minimum revenue may be inclined to raise their offer prices, to make up for the pro rata quantity reduction. The magnitude of this distortion will depend upon how much CSOs are reduced (which will depend upon several factors; in the example the reduction is rather small, 2%) and also the owner's cost structure and risk tolerance. This distortion would seem to be less significant than the distortion raised by the Public Power approach, however, it is still a distortion of offer incentives.

3. The rate P2

Because the offer price distortion is repaired, the P2 clearing price is less arbitrary than under the Public Power proposal. However, the P2 price is still the result of an abstract notion of a "competitive" clearing price formed based on a calculation under which some resources that are in the market (the STM resources) are essentially treated as if they are not in the market, through administrative mitigation; and this mitigation may continue for years. Thus, the P2 price is still a hypothetical.

As noted above, my 2010 affidavit in the APR proceeding raised additional issues with the two-tier pricing concept, of which some are applicable to these new proposals (summary on p. 36 of the affidavit, which was linked above).

V. Two-Tiered Pricing Proposals: Other Details

A few other details of the two-tiered pricing proposals are notable:

1. Both proposals refer to Market Rule 1 Appendix A.21 as the definition of resources subject to mitigation.
2. Both proposals call for expanding this definition to include Existing Resources.
3. The Public Power proposal would add a new definition of "Certified Load Asset Resources" that would offset the capacity resource obligations of specified Load Assets, in effect providing a self-supply exemption. (FYI, for PJM's capacity market, FERC approved a self-supply exemption that is subject to "net long" and "net short" limits.)
4. The NRG proposal calls for eliminating the 200 MW Renewable Technology Resource Exemption, while the Public Power proposal calls for retaining it.
5. Both proposals call for STM resources to continue to be subject to mitigation in subsequent FCAs, until such time as they are able to clear under the higher Stage 2 price.

VI. Two-Tiered Pricing Proposals: Summary

As noted above, two-tiered FCM pricing proposals attempt to resolve the conflict between three competing capacity market design objectives:

1. recognizing the contribution of the STM resources to resource adequacy by granting them CSOs;

2. establishing a “competitive” FCM price for compensating existing and attracting new competitive (non-STM) resources, that is not suppressed by the offers of STM resources; and
3. clearing a reasonable total amount of capacity at a reasonable total cost.

The two proposals put forward at IMAPP both fulfill the first objective, so perhaps the main tension is between the second objective (which may be highest priority for capacity sellers) and the third objective (which may be highest priority for consumer interests).

In addition, a satisfactory solution must also adhere to other market design principles and not create significant new problems, such as the incentive issues described above.

Four Possible Functionalities of IMAPP Reforms

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Anything we design will need to serve a function and its design ought to depend on the function it's intended to serve. I see four possible functions for market reforms with respect to public policy. They are not mutually exclusive and may be unavoidably interdependent in some designs, but viewing all proposals in light of their function and interaction with public policy could help parties think through what they want to do and provide a frame work for calibrating the pluses and minuses of proposed designs. The four general functions proposed market reforms could serve (again, not mutually exclusive) are;

1. Replace legislative mandates and state programs with market based procurement.

2. Supplement or add to existing incentives in legislation to increase the amount of renewables beyond legislative mandates.

3. Assist in the collection of money and the allocation of cost for state mandates.

4. Remove Market Features that make public policy more difficult or costly to achieve.

There is also a fifth function that is not directly related to advancing renewable policies per se and may in some instances interfere with the functionalities above; i.e. purely defensive reforms designed to protect price formation and encourage continued, non-public investment in needed or desired non-renewable resources or infrastructure. I leave this last off the list for now because I do not think it was the main point of the IMAPP process. By that I mean, I presume public officials were looking for more out of this than a successful defense of price formation for non-renewable resources. Such protections may become necessary to keep the lights on, but it doesn't necessarily make renewable expansion easier or cheaper, at least not directly.

The four functionalities above should be useful in analyzing and evaluating proposals, even if the proposals are not *intended* by their proponents to function in one of the four ways listed. For instance, a Carbon adder regime may be suggested as a way to "eventually" replace individual state mandates or procurements and that may be its intended effect. But in the interim, in the absence of immediate repeal of state laws, it is either an additive incentive designed (intentionally or otherwise) to get more renewables in a context where the states already are in disagreement about how much and what to buy, or if it isn't getting more built, it is either wasted or serves the function of collecting money in the market (functionality 3) to offset the costs of bilateral contracts. Thus, thinking through each proposal in terms of what it will do under the four functionalities and deciding whether we are happy with what it will do, or can design it in a way that gets us happy, is the minimum analysis needed to guide design. If the states could identify which functionalities they are looking for[1] we could have a better and more informed discussion about whether there is a practical design to get there and develop a roadmap for the pot holes we want any design to avoid along the way. By framing each proposal in terms of how it will function in both the short and longer term, we might even develop a sequencing roadmap as to what we should get done first or how we could ramp in market incentives so as not to duplicate legislative ones.

[1] For instance; do we want additional incentives beyond current state policy for renewables essentially "legislated" by NEPOOL or FERC? And if not, how do we build a design that avoids that?

Below I offer some discussion of questions that I think arise with respect to the four functionalities. It is difficult not to have this sound argumentative, and I understand that every framework for analysis reflects the priorities of the author. But it is difficult to see how we can reasonably design something without examining closely how it will function and what it will do, in this case specifically in relation to public policies favoring renewables, or, as NESCOE and others have noted, the broader range of economic and R&D legislative objectives.

1. Replacing Legislative Mandates:

a. It is not reasonable to assume that, *in the short term*, legislators will repeal existing legislation and rely on the market. That means that at least in the short term, any market reform will work in conjunction with or additively too legislatively driven procurement. That is properly analyzed under 2 or 3 below.

b. Assuming, however, that our goal (or at least one of them) is to design something that can replace or reduce the need for legislative mandates in preference to reliance on a regional market, clearing price type of mechanism in either the energy or capacity market, what is the target procurement we are trying to replace?

- Specific resources and types in particular locations?
- A specific number of clean energy KWHs (is current legislation reducible to this?)
- A single regional or six individual state procurement targets?
- Other.

Set aside for a moment the logistical problems of trying to design a regional procurement product or mechanism that would satisfy any of the (*) items above, WHAT IS IT THE STATES WANT ON THAT LIST? Again, we do not need specific amounts at this stage, just the **structure** of procurement targets if and when they are ever established. If the states cannot identify a specific structure of the form above, it will be difficult to quantify not only how much to procure but also what to procure.

If, on the other hand, the states would support market reforms in the vague hope (I do not thereby imply such hopes are unreasonable, only that they are not precisely quantified) that added incentives in the market will eventually persuade state legislatures that they don't need to continue out of market procurement, then our design questions need to focus on functionalities 2 and 3 below and include some risk adjustment for the unpredictability of legislatures. The States would need to provide some input on how much additionality and/or potential duplication or expansion of incentives they are willing to expose consumers to in order, essentially, to incent legislatures to rely on the market instead of mandates. A carbon adder could reasonably be calculated to meet an agreed upon level of incentive with some analysis under 2 and 3 below. None of this is an exact science. It is not necessarily unreasonable to put general incentives in place to drive desired outcomes even for largely irrational activities like legislation. But we do need to decide how much we want to spend on that and the best way to structure it.

2. Supplemental or Additional Incentives.

a. It is inevitable that any reform we institute will operate in conjunction with existing legislative mandates, at least in the short term. I will try to separate considerations of additionality here from the issues in 3 where a design might just be a way of collecting the money for state mandates without adding to the incentives.

If, for whatever period of time, market reforms exact $$ from consumers to promote renewable expansion in addition to the $$ already exacted by state policies that require them to pay bilaterally for contracts, then,

- What level of additional investment should the incentives target?
- Should they target a regional procurement amount or state by state targets?
- Should it target only specific resource types in particular locations or can the states agree to a simple zero carbon objective?
- Other.

b. the above list is not exhaustive, but without some parameters like this it will be difficult to design a particular procurement mechanism or to judge the level of duplication (are we paying people simply to do what ratepayers have already paid them to do bilaterally?) or incrementalism (how much more did we get for our money than what we would have gotten bilaterally under state procurement?). But assuming (as everyone seems to, though, IMHO rather blithely) that we can accurately assign and allocate costs among states to everyone's satisfaction, WHAT IS IT THE STATES WANT FROM THE ABOVE LIST?

Do the states (or some of them) even want (in either the short term or the long term) additional incentives and costs beyond those in current legislative mandates? If so;

- Decided by whom?
  - State legislatures?
  - State PUCs either with or without specific legislative authorization.
  - Agreement among the Six Governors?
  - Some or all of the above in addition to the stake holder process?
  - Some or all of the above and a unilateral 205 filing by the ISO?
  - A unilateral 205 filing by the ISO based on its best estimate of the additional incentives the states collectively but informally (or at least by some mechanism other than those listed above) say they want?

- Other?

The above list presents difficult choices but is not meant simply to impose difficulties. Every proposal put forward has responsibly recognized that there must be some mechanism to decide how much to buy and at what cost. The proponents have not ducked these issues, but absent some further input from the States as to how, for instance, to calibrate (or decide how to calibrate) a specific carbon adder, they can make suggestions but cannot settle on a specific procedure or mechanism.

Let us assume, the States are willing to have consumers pay some additional amount on the vague premise (again, I do not imply unreasonable, only not precisely quantified in terms of the * items above) that a general market incentive to encourage renewables is a good thing and within their purview to authorize; proponents still need some input into how much additional incentive this justifies either regionally or state by state. Again, a general incentive for carbon reduction is not unreasonable, even if exactly how much additional reduction or investment we'll get can't be forecast. But I don't know that the states want either NEPOOL or FERC to be the arbiter of how much is enough, which means that to design a product we need to know whether States want additional incentives and if so in what range. If states do not want additional incentives (or want only some minimal amount which may be unavoidable in order to achieve other objectives) then proponents would do well to design a market payment and pricing scheme to be as nearly as possible a facilitation vehicle for collecting and allocating costs and payments in a way that is consistent with state allocation principles. This would come under functionality 3, below.

3. <u>Collecting money and allocating costs.</u>

a. It might be possible to construct a market clearing mechanism with something like a carbon adder that essentially served as a vehicle to collect from the market the costs (or part of the additional costs) of bilateral contracts doled out as capacity or energy payments to renewable resources. Those resources would then deduct those revenues from amounts paid by consumers under bi-lateral contracts. I presume that any well-structured contract would have that feature anyway (i.e. money from sales in the market should offset bilateral costs to consumers).

In general, this is not an unreasonable construct to try to achieve on a regional basis as long as there is some agreement between the states that such an offset mechanism is not imposing other costs (like a higher clearing price) on those who achieve no benefit from any such write off of bilateral expenses.

Many presenters have assumed that if there were agreement on cost allocation, it would be "easy enough" to allocate costs. In fact, there is agreement on cost allocation: No state can or will pay for any other state's mandate. This has been said to be a "bottom line" principle. Unfortunately, I think this bottom line could make any regional solution very difficult to allocate acceptably. The questions arising under this functionality aren't a function of state intransigence but of the fundamental difficulty of assigning costs and benefits from actions and price effects in an integrated regional market. I run through a few possible scenarios below just to highlight the sorts of questions and challenges this functionality when it is combined with the states bottom line insistence that no state pay for another state's mandates:

- Let us assume the most simplistic formulation; the amount of added cost to all consumers in the market from a regional higher clearing price is exactly quantifiable and can be allocated back to the holder of the bilateral contract(s).

    1. If the regional cost is higher than the amount the resource gets in the market and pays back to the contract holders (hard to see how it wouldn't be with ALL resources, not just the bilateral ones getting the higher price) then the costs allocated back to the contract holder puts them in a worse position than they would have been without the mechanism. How is that helping?

    2. On the other hand, if we have separate clearing prices or adders only for the bilateral resources that (somehow) don't affect prices for other resources or amounts paid by other consumers (presumably all those adder costs are allocated back only to the bilateral purchaser), then any revenues received from the market are simply coming out of one pocket and going back into the other and we have created a very complicated mechanism that does no more than put everyone is the same position as they would have been just paying for the bilateral contract. How is that helping?

- Let us assume despite the "bottom line" above, the states are willing to tolerate some "leakage" as long as rough justice is preserved. Well, how rough? To take the simplest example of a possible complication, if an out of market contract lowers the capacity clearing price but raises the energy clearing price because of an adder to reflect carbon or anything else, should all states who benefited from the lower capacity price be willing to pay some portion of the higher energy price or do they get to "free ride" on the benefits provided by the holders of the bilateral in the capacity market? What is the "but for" state against which costs and benefits will be calculated?

b. I feel a regional agreement on targets would be necessary to make market reforms aimed at this third functionality workable. Now, the states, *could* agree to an allocation without getting into the complications above, but that is NOT how I am reading the message with respect to "no state pays for another state's mandates***". If that message should be tempered or interpreted differently, I think it would be very useful for proponents to know what the degree of tolerance is for departure from precision.*** If it cannot be tempered then I think the notion of setting up a regional mechanism and then reallocating costs and benefits to suit six individual state preferences is likely impractical.

Again, there is no reason for that principle to be absolute and I do not advocate one way or another on whether it should be, but we can't design something on a regional clearing price basis that will satisfy that principle if it is, in fact, absolute. That is a practical, functional implication of the state's principles that I think people have paid too little attention to.

4. <u>Get Out of the Way</u>.

a. Even market reforms designed not to hinder or make more expensive the implementation of public policy may incur costs that would be hard to allocate per above. Simple case is the NRG two tier pricing which would allow bilaterally procured renewables to clear. NRG presents a reasonable design approach, but it is not revenue neutral in terms of what existing resources will get paid as opposed to simply opening the gates and letting everything clear with no MOPR. There may be other designs we could adopt that had the same objective of removing market impediments to renewables but might nonetheless stray into other functionalities that we don't want. It is certainly not unreasonable to seek to minimize direct conflicts between market requirements and state policy, but this is a considerably less ambitious goal than presented by many of the current proposals. If this is the main functionality the states are looking for, it would be very useful for participants to know that and adjust their proposals accordingly.