

CAPACITY WATCH

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EXECUTIVE SUMMARY

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There are active developments transpiring in each of the three Northeast capacity markets, all of which have significant consequences on capacity clearing prices. In PJM, FERC has ruled on the Minimum Offer Price Rule (MOPR) and has largely approved the overall PJM filing, with the exception that the proposed three year mitigation will be changed to no time limit for the mitigated units.

In New York, the NYISO filed a compliance filing on March 29 in response to the January 29 FERC order ruling on the 2011 to 2013 demand curve reset process. The FERC January 28 order was very bullish for New York City capacity prices (almost double the original NYISO proposal) and the NYISO compliance filing, if accepted, will result in New York City reference points that are only about 10 percent lower than implied by the FERC ruling.

In New England, FERC has directed ISO-NE to develop a set of mitigation rules that would mitigate new entry in relation to generator class net CONEs. FERC also rejected ISO-NE's proposal for a two-tiered pricing result. ISO-NE had proposed that two prices be applied, including one that treats out-of-market resources separately from existing generators.

In the front section of Capacity Watch, ESAI examines the issue of long term capacity price equilibrium and compares the conventional wisdom of equilibrium at net CONE with ESAI's expectation of long term equilibrium at a discount to net CONE.



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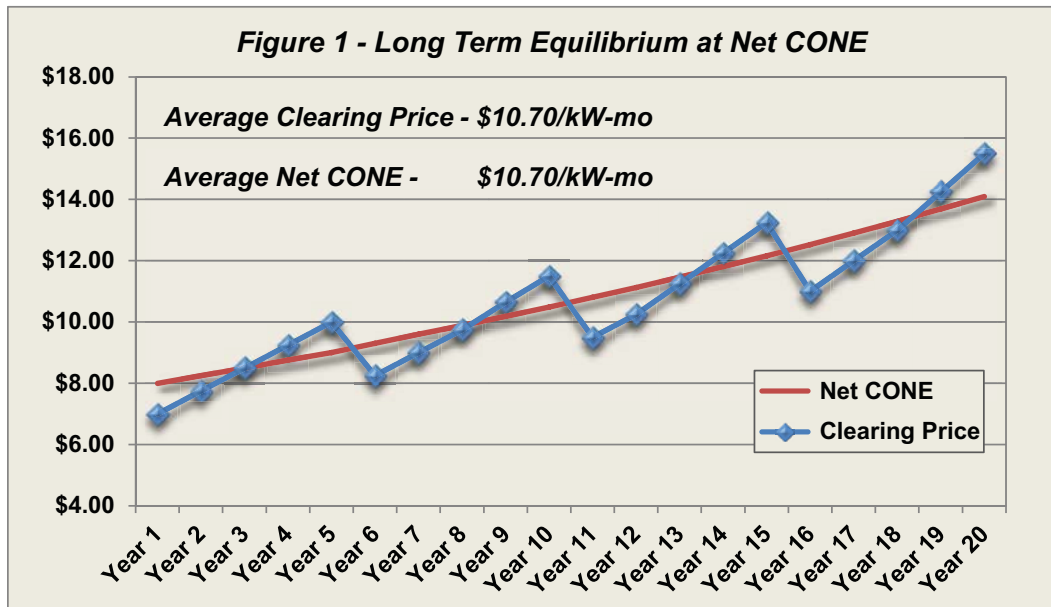
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ASSESSING LONG-TERM CAPACITY MARKET EQUILIBRIUM

When developing outlooks for the capacity markets, there is an element of transparency in the first five years of a projection. During this nearer term time frame, load growth trends are more predictable, generator additions can be projected, and retirements can be reasonably estimated based on announcements or prevailing market conditions. Beyond five years, markets that are in surplus (such as New England and New York Rest of State) rely largely on load growth with some projection of retirements to erode the surplus. When generator surpluses decline, a fully functional capacity market will send a price signal to market participants that will reflect the cost of new build.

Conventional wisdom for long-term capacity prices is driven by orthodox economic theory under assumed perfect market conditions. When the market yields energy and capacity price signals that provide an incentive for a developer to meet the costs of a new generation facility, the developer will begin the process of permitting and constructing a new plant. This price signal is generally referred to as the net Cost of New Entry (CONE) and represents the amount of revenue that the developer needs to receive from the capacity market to meet his cash flow needs, after allowing for energy and ancillary service revenues. $\text{Net CONE} = \text{Gross CONE} - (\text{Energy} + \text{Ancillary Services})$.

The original Northeast capacity market designs were short term in nature, and thus anticipated that capacity clearing prices could move above net CONE between the period of the initial 'green light' price signal and the entry of the plant into the capacity market. The new entrant(s) would presumably drive prices below net CONE for a period of time before a cyclical recovery and a second new build price signal was projected. Figure 1 illustrates the net CONE long term equilibrium outlook as described above.



The conventional wisdom for long-term equilibrium at net CONE makes several assumptions that, taken together, represent a substantial departure from actual market conditions:

1. ‘Perfectly’ rational investors -

A perfectly rational investor would be one that waits for a price signal to actually occur before spending any serious development money on a project. For a typical combined cycle project, a three-year lag would be adequate between the ‘green light’ price signal and the entry of the new capacity to the market.

2. All market participants face the same level of net CONE –

Although capital equipment costs are somewhat uniform, prices can vary by technology and vendor. Every developer will have different cost structures for actual development, permitting etc. Land costs and local taxes can vary greatly between locations and finally, the costs associated with financing can vary greatly depending on the credit standing of the borrower and the leverage applied. All of these factors can result in a range of net CONE results for different projects that could skew the results as compared to the ideal long term average shown in Figure 1.

3. No market interference -

Generation projects that are subsidized in any way will have incentives to offer into capacity markets at levels below costs faced by more market-driven competitors. Capacity that is supported by out of market PPAs will be able to offer in at lower prices than purely merchant competitors and will therefore skew the results from the ideal net CONE equilibrium.

4. Size does not matter -

The price signal will be seen by a number of developers in the market. If a number of projects are developed concurrently, then a wave of capacity could enter the market that would depress prices beyond what would be assumed in a long-term pricing outlook set at net CONE.

Combined Cycle Plant Should Be Long-Term Benchmark

The capacity market designs in the Northeast markets have generally utilized combustion turbines for the determination of net CONE. In New York and PJM, CT net CONEs are used to define the parameters of the demand curves in those markets. However, due to their higher energy revenues, combined cycle plants tend to have lower net CONEs than combustion turbines. Therefore, we believe that the combined cycle net CONE is what should be used as the more competitive level for determining the long term equilibrium pricing.

ESAI LONG-TERM OUTLOOK – DISCOUNT TO CC NET CONE

In ESAI's long-term outlooks, a discount is applied to the combined cycle net CONE in assessing long-term equilibrium pricing. Our long-term equilibrium view is set at 90 percent of combined cycle net CONE to reflect the fact that the capacity markets are not ideal and are subject to a number of factors that can drive prices lower than expected under perfect conditions.

A long-term discount to the combined cycle net CONE can develop for a number of reasons, including competitive factors, the actions of irrational investors, and the influence of unmitigated buyer-side monopsony power. These issues are highlighted below:

Competitive Factors

As noted above, developers that can keep costs low will have an advantage and can offer below a benchmark net CONE and still be economic. Some projects can have significant advantages with respect to brownfield sites, low interconnection costs etc. Often, aggressive developers can bring in quality projects on a no-frills budget that, when paired with a high quality investor, can result in lower total capital costs with good leverage and competitive financing terms. This type of project might beat more conventional net CONE cost benchmarks.

Irrational Investors

The subject of irrational investing brings into focus the human element of influences on the capacity markets. Typically speaking, a person who is irrational is usually only irrational in the eyes of others and is not irrational in his own eyes. A decision to develop and build a generation project at prices that are below net CONE may appear unfounded to outsiders, but the developer himself is motivated for reasons that might transcend conventional wisdom, such as:

- *Vision* – The project sponsor sees a need developing for the project in anticipation of stronger load growth, additional retirements, or changes to the transmission topology that the rest of the market does not see. While some may consider this alternative viewpoint on the market as irrational, it could be considered brilliant if the project sponsor completes the project and his vision comes to pass as the project achieves commercial operations. As highlighted on occasion in our publications, the collective wisdom of the marketplace is not always correct.
- *Positioning* – A project sponsor may understand that the economics of his new build plant will fall short of required cash flows in the first few years, but that by investing ahead of the curve, it will discourage others from developing competitive projects. In this manner the shortfall in revenues is expected to be more than made up for by the subsequent 'pop' in energy and capacity prices that will later make the plant wildly profitable.

- *Sunk Costs Not Really Sunk* – Developers are by nature among the most tenaciously persistent people around. It is not uncommon for a private developer to put in ten years and perhaps tens of millions of dollars into a single project that has questionable economics. (If in doubt, please refer to the development time and costs as well as the currently half-committed status of the Cape Wind project.) A rational investor might cut his losses, lick his wounds and move on. A particularly wealthy developer may have the financial fortitude to stick to his guns and not regard the development costs as lost, but as a part of the overall costs yet to be recovered.
- *The Influence of Auctions* – Participation in an auction can completely alter the behavior of an otherwise totally rational market participant. Take for example the forward auctions in PJM and New England. If a developer clears his project in the auction, he will commence construction of the project. In PJM, it is a one-time offer, so the owner must put in a price that will allow it to clear. If the owner offers the capacity at cost (*i.e.*, the plant's net CONE), then the project might not clear and the owner will incur the significant costs of delaying the project for a year. Therefore it is in his interest to obtain a forecast of the capacity price in the auction and to offer a price that he believes will clear. A one-year 'hit' on his pro forma cash flows might not be a huge blemish on a 25-year project.

The descending clock auction in New England is another example of how rational investors can turn 'irrational' during an auction. In the descending clock auction, the price drops in every round and some capacity offers may drop out with each decline. When the project owner participating in the auction sees the price drop to the first incremental level below the plant's cost, the owner should exit the market. But, if the market clears at only one increment below cost, then the owner has a clearing price that is close to his requirements. So the temptation is very strong to stay in the auction. With each increment lower, the owner is faced with the same dilemma – stay in at a lower price, or wait until next year. It is not unlike the analogy of placing the frog in the pot of cool water and then turning up the heat - it doesn't feel bad until it's over and you're cooked.

There are myriad ways in which investors might behave irrationally in the eyes of the broader market, although this behavior may be part of a determined strategy that is clearly rational from the viewpoint of the project sponsors.

Of course, the presence of investors who are truly irrational is almost unavoidable. Most of these developers are weeded out by the complex processes of permitting, interconnection applications and the detailed vetting associated with financing. In the current financial environment with tight credit and the general unwillingness to finance merchant projects, it is much more difficult for an uneconomic project to move towards construction. The current strict financial environment is a result of conditions prior to 2005 when a large number of newly built merchant projects started operations, each one of which was not only going to be profitable, but be further leveraged by a team of top-notch traders who would opti-

FERC STRENGTHENS MINIMUM OFFER PRICE RULE

On April 12, 2011, FERC approved PJM's proposed revisions to Minimum Offer Price Rule (MOPR) designed to better address buyer-side market power in the Reliability Pricing Model (RPM) capacity market. Though the MOPR has been in place since creation of RPM in 2006, recent legislation in New Jersey and Maryland caused PJM to revise the rule to address these states' deliberate attempts to depress RPM capacity prices in eastern PJM. In general, the revisions substantially strengthen the MOPR and will prevent out-of-market, state-sponsored generation from depress RPM clearing prices. Accordingly, the revised MOPR should provide a bullish counterpoint to the addition of state-RFP-sponsored generation in eastern PJM.

Background and Current MOPR

Established as part of the 2006 RPM settlement to address buyer-side efforts to lower clearing prices by offering resources below competitive costs (*i.e.*, monopsony market power), the present MOPR established three screens to be applied to offers to sell into the RPM auctions.

First, the MOPR applies a **conduct screen**, which uses a benchmark price to determine whether a sell offer may be non-competitively low and thus should be mitigated. The benchmark price is based on the Net Asset Class Cost of New Entry (CONE) values for a proxy combustion turbine (CT) and combined cycle (CC) units. For a CC or a CT, the existing MOPR sets the lower bound for a new resource's offer at 80% of the Net Asset Class CONE. For other resource types not expressly permitted to submit a zero-price offer (see below), the screen is set at a default level of 70% of the Net CONE for a CT.

If an offer fails the conduct screen, the current MOPR then applies an **impact screen**, which compares the clearing price with and without mitigation to determine the price impact of the resource. To apply the impact screen, PJM reruns the auction with the below-threshold offer at its unmitigated value to measure the impact on capacity clearing prices. If the subject offer reduces the clearing price by more than 20% to 30%, depending on the locational deliverability area, or more than \$25 per MW-day, the offer would fail the impact screen. If not, the offer has passed the impact screen and would not be subject to mitigation (even if it failed the conduct screen). (Note that the recent FERC order removes this impact screen).

Finally, if an offer fails both the conduct and impact screens, the existing MOPR then applies a **net-short requirement test** to determine if the seller is a net buyer, *i.e.* it buys substantially more capacity from the relevant RPM auction than it is selling into it. The net-short requirement test is intended to distinguish between: (a) sellers of generation who as net buyers may have incentives to depress market clearing prices below competitive levels, (b) sellers of generation who as net sellers may have incentives to increase market clearing prices above competitive levels. (Again, note that the recent FERC order removes the net-short

requirement test).

A sell offer that fails all of these screens is subject to mitigation, meaning that the uneconomic offer is increased to a competitive level, set at 90 percent of the net CONE for the type of asset (Asset Class). If there is no applicable asset class for a resource type, the offer is mitigated to 80% of the Net CONE for that LDA.

The existing MOPR also includes an exemption provision that eliminates mitigation for certain resource types – nuclear, coal, hydro, integrated gasification combined cycle (IGCC) and upgrades or additions to existing capacity resources – and for resources undertaken pursuant to a state mandate. In addition, the existing MOPR only applies to the first auction in which a planned generation resource is offered, regardless of whether the resource clears in that auction. Thus, any mitigation occurs only for one year.

FERC's April 12 Order

The April 12 order approved virtually all of PJM's proposals to revise and strengthen the MOPR. The major changes are:

- **Higher Conduct Screen Threshold** – FERC approved PJM's proposal to raise the conduct screen threshold from 80% to 90% of net CONE. Furthermore, FERC approved the proposal to use updated net CONE values, including updated gross CONE values and energy and ancillary services revenue offsets for CT and CC plants, tracking changes in construction costs by escalating at the Handy-Whitman index, and incorporating locational differences in capital costs. The threshold of 90% of net CONE will apply for both the asset class and its respective LDA.
- **Elimination of Impact Screen and Net-Short Requirement** – FERC approved PJM's proposal to eliminate both the impact screen and the net-short requirement test, meaning that only the (now more stringent) conduct test will be applied and failed offers will be subject to mitigation. FERC agreed that allowing offers that pass the impact test (less than \$25/MW-day or a 20%-30% reduction) to still depress prices is inappropriate. Moreover, eliminating the impact test significantly simplifies application and administration of the MOPR, as the requirement to rerun the auctions to model price impacts would be removed. As for the net-short requirement, FERC found that the existing test can be easily gamed and evaded – a net buyer or an entity acting on its behalf can structure a new entry transaction in such a way (*e.g.*, through a purchased power agreement) that achieves the same price-depressing effect without triggering the MOPR.
- **Changes to Types of Resources Exempted** – FERC approved PJM's proposal to include wind and solar resources in the types of resources exempt from the MOPR and allowed to offer zero-price in the auctions. FERC also approved PJM's proposal to eliminate the exemption for upgrades and additions to existing capacity resources. In sum, the new MOPR will ap-

ply exclusively to new combustion turbine and combined cycle generating units, as well as upgrades to existing combustion turbine and combined cycle generating units. Whether new or upgrades to existing units, virtually all of the resources subject to the revised MOPR will be gas-fired units.

- **Elimination of State Exemption** – FERC approved PJM’s proposal to eliminate the exemption from mitigation for resources pursuant to state mandates. Several provisions of the revised MOPR allow for appropriate exemptions of generation that could be the result of state mandates, such as inclusion of wind and solar as exempt types of resources.
- **Lower Unit-Specific Net CONEs Allowed** - FERC also approved a mechanism for generators to request a different value for a competitive offer if its actual costs are lower than the benchmark level. FERC ruled that PJM and its market monitor must first review a generator’s request and justification for offers below the reference levels, before the generator submits the justification to FERC for review. This rule would allow a new generator to offer below the 90 percent of net CONE mitigation level at its approved unit-specific net CONE. It would not, however, be allowed to offer below this level.
- **Duration of Mitigation** – FERC approved the PJM market monitor’s proposal to extend mitigation past one auction (one year). Specifically, FERC found that the MOPR offer floor should apply to each new resource in the base residual and each incremental auction until the resource demonstrates that its capacity is needed by the market at a price near its full entry cost – by clearing one of the PJM capacity auctions (base residual or incremental) at an offer price near its full cost of entry. In other words, the MOPR would apply until the resource has proven that it is needed by the market, after which the resource would be treated as an existing capacity resource and would not be subject to the MOPR. The intent is to mitigate a resource (or require it to justify a lower bid) until after it has “naturally” cleared the auction – a period that could last several years.
- **Elimination of Self-Supply Exemption** – FERC approved PJM’s request to clarify that planned generation designated by a load serving entity as self-supply should be subject to the MOPR and its offer floor until it clears in the RPM base residual auction. FERC noted that the PJM tariff provides an alternative for those load serving entities that wish to bring new generation resources into the PJM capacity market without risk of being mitigated under the MOPR – the Fixed Resource Requirement (FRR) alternative. Under the FRR, load serving entities effectively opt out of the RPM market by electing to satisfy their capacity obligations under the FRR alternative. FERC noted that the FRR option is the alternative for load serving entities wishing to secure their own capacity resources outside of a competitive market, whether as directed by state-authorized plans or pursuant to other considerations. But, in order to protect the integrity of the RPM market, FERC found that new self-supply seeking to participate

in the RPM market must compete with other planned generation on the same competitive basis.

Analysis and Implications

The revised MOPR is a tremendous victory for generators, who have unsuccessfully fought efforts by New Jersey and Maryland to sponsor thousands of MW of new capacity to deliberately lower eastern PJM capacity clearing prices. The revised MOPR should keep higher prices in place for eastern PJM despite the addition of 2,000 MW or more in New Jersey pursuant to that state's recently enacted legislation.

But, not all state-sponsored generation in eastern PJM will be subject to the new MOPR. For example, the newly granted exemption for wind and solar resources may have a significant impact, as several eastern PJM states (including New Jersey) are contemplating substantial development of solar and offshore wind resources. While the capacity value of these resources will be reduced due to lower capacity factors, they will nonetheless be allowed to enter the RPM auctions at a zero-offer price, which will depress the clearing price in these eastern zones.

In addition, demand resources should be able to demonstrate costs below the MOPR's benchmark levels and thus be allowed to offer at low prices. Despite the fact that some of these resources will be supported by payments outside of the capacity market, it is likely that demand resources will not be mitigated, thus placing considerable downward pressure on capacity clearing prices.

By narrowing application of the revised MOPR to new CC and CT units (as well as upgrades to existing CC and CT units), PJM is effectively imposing a form of cost-based regulation and rate recovery for a specific generation technology entering the RPM capacity market. Owners of existing CC and CT units planning upgrades and developers of new CC and CT units will face benchmark offer levels imposed by PJM, meaning that their units may not clear the RPM auctions. This targeted technology choice further tips the scales towards the PPA-driven development model for new generation. In other words, whatever opportunity new gas-fired generation had to be developed under a "merchant," market-driven model – an admittedly low opportunity these days – is considerably reduced by the MOPR's exclusive application to CC and CT units.

Whether appropriate or not, the virtual cost-based regulation imposed by the PJM MOPR effectively means that other generation technologies – such as coal, IGCC, wind and solar – may actually benefit. New coal-fired units (IGCC or otherwise) and upgrades to existing units may be helped by the MOPR, particularly if the PJM backbone transmission projects are built. With this new transmission in place, we would expect a convergence between RTO and MAAC RPM clearing prices – increasing capacity prices for western coal units but decreasing them for eastern PJM capacity. New coal-fired capacity would have a better chance of clearing the auctions as it would escape mitigation. Furthermore, the generally bullish impact of the MOPR on capacity prices may help existing coal units fund

As outlined below, the recent FERC order has eliminated the Out-of-Market auction and associated forecast for new out-of-market generation. ESAI's current FCM forecast is therefore now based on a single auction that will no longer allow out-of-market resources to participate below their economic net CONE values. Each new generation unit that offers in to the market will be assigned a generator class net CONE minimum offer price. Units that might have offered as price takers are now forced to line up in the offer stack according to their generator class and therefore will not be available to drive prices lower in the current high surplus environment.

FCA5 and FCA6 To Clear At Floor

Although FERC has provided some definition to the market outlook as a result of their order, it will be some time before ISO-NE will be able to develop and finalize an FCM redesign that will be ready for implementation. ESAI believes that is unlikely that a redesign can be developed, approved and implemented prior to the FCA7 (2016/17) auction. Given the long lead time for the redesign, our outlook for both the 2014/15 (FCA5) and 2015/16 (FCA6) auctions anticipates that the price floor of 0.6 x CONE will apply for both of these auctions. The large generation surplus is high enough that the clearing prices for FCA5 and FCA6 will be at the floor (\$3.21/kW-mo for FCA5 and \$3.31/kW-mo for FCA6).

FCA7 and Beyond

In meetings with stakeholders at the end of April, ISO-NE indicated that it is struggling to develop a schedule to implement the FCM redesign for FCA7 (2016/17). ISO-NE is leaning towards proposing to FERC an implementation schedule for FCA8 (2017/18). ISO-NE's proposal will be filed at FERC by May 13. However, at this time it appears likely that the auction floor price mechanism will remain in place through FCA7 and removed for FCA8 concurrent with implementation of the new offer-floor mitigation mechanism.

Although FERC has ordered ISO-NE to develop their capacity auction based on a single auction with assigned (mitigated) price offers for new capacity not exempt from the mechanism, the rules have not yet been defined. Therefore, it is unclear what price levels will be assigned to the different generator classes such as combined cycles or combustion turbines. It is also unclear what generator types will be exempt from price assignments and will be free to offer as price takers (for example, under the PJM Minimum Offer Price Rule, nuclear, coal, IGCC, hydro, wind, and solar are all exempt from mitigated price offers).

Static De-list Bids Will Govern Future Prices In Surplus Environment

In its recent FCM order, FERC approved the dynamic de-list maximum threshold of only \$1.00/kW-mo; a significant drop from the 0.8 times CONE dynamic de-list offer maximum that applied in previous auctions. This means that dynamic de-list bids cannot begin to affect the market outcome until prices drop to \$1.00/kW-mo. Dynamic de-list bids thus become somewhat ineffectual and only serve to avert the 'disaster' scenario in which prices might fall towards zero.

Although the dynamic de-list bid option has become rather ineffective as a part of generator bidding strategy, the static de-list bid option can accomplish the same objective of removing existing capacity from the market at a price (thus affecting the ultimate outcome). The main difference is that static de-list bids must be registered ahead of time. While the dynamic de-list bids potentially offer much more flexibility to the generator during the auction (assuming that they could de-list at higher prices), the \$1.00 price threshold severely limits the utility of the dynamic de-list option. Generators that may have been active de-list bidders will now migrate to the static de-list bid option in an effort to keep prices from falling to very low levels in the face of large pool-wide surpluses.

The characteristics of the descending clock auction play an important role in our FCM capacity pricing outlook. Because of the continued use of the clearing price floor, the dynamics of the final clearing price absent a floor have not yet been in play. Looking to FCA8 and beyond, the final clearing prices in the declining clock auctions will be dictated by the following dynamics:

1. The existing surplus must be eliminated in the auction in order to have a defined clearing price. (The auction was designed with a vision that a forecast capacity deficit would be eliminated by the addition of new generation.)
2. If the surplus is not eliminated, the clearing price will be zero.
3. The surplus can be reduced through:
 - a. The rejection of de-list bids. This occurs for reliability purposes; the rejected capacity is removed from the surplus at the 'top' of the stack and is therefore a direct reduction prior to the start of the auction).
 - b. Static, permanent, or export de-list bids. The offer levels will be subject to the generators offer strategy.
 - c. The reduction of imports into New England. The offer levels will be subject to the alternative values in the New York Rest of State market.
 - d. Dynamic de-list bids can reduce the surplus but only at the deemed offer level of \$1.00/kW-mo or lower.
4. New generation will enter the auction at either its class applied mitigated net CONE (possibly with an applicable discount), or, at its unit-specific net CONE as cleared by the market monitor (rules to be determined). The entry of new generation adds to the surplus the top of the stack and also must be eliminated in order to deplete the surplus to zero.

As the descending clock auction progresses, it is probable that most new generation will not clear as prices drop. As the new generation drops out, the existing surplus will then be cleared by static de-list bids. Some low cost resources such as wind or DR may drive prices lower and will be then be offset by de-list bids,

For a description of ISO-NE's paper hearing proposals, including the now-rejected two-tier pricing mechanism, please refer to our July 2010 *Capacity Watch*.

FERC's April 13, 2011 Order

The April 13 order rejects the APR proposals made by ISO-NE and directs ISO-NE to develop (together with stakeholders) a buyer-side mitigation mechanism that relies on benchmark prices and an offer-floor price mitigation mechanism. In addition, the April 13 order:

- Approves ISO-NE's proposal that OOM resources that cleared in the first three FCAs (so-called "historical OOM") should not be "carried forward" and used to trigger the APR;
- Extends the current price floor mechanism through the sixth FCA and forward until revisions to the current APR are implemented;
- Approves the ISO-NE proposal to "model all zones all the time" in the FCAs, with the eight (8) existing energy market load zones – CT, SEMA, WCMA, NEMA/Boston, VT, NH, and ME – as the initial basis for modeling potential capacity zones in the FCAs;
- Approves ISO-NE's revised supplier-side mitigation proposal, including a revised threshold of \$1.00 per kW-month for market monitor review of dynamic de-list bids;
- Approves ISO-NE's proposals to eliminate or replace the current uses of the CONE parameter.

We provide more detail on the provisions of FERC's April 13 order below.

APR and Monopsony Market Power

Recall that the purpose of the APR was to set a market-based capacity price when capacity deemed to be out of market (OOM) prevents new entry from setting the price. In essence, the intent of the APR is to mitigate buyer-side (monopsony) market power and address situations when out-of-market actions can create "artificially" low prices for certain years.

Under FCM, OOM capacity resources are new resources that requested to offer below 0.75 times CONE but were denied by ISO-NE after review by the market monitor. In most cases, OOM capacity resources hold contracts that ensure full recovery of fixed costs or otherwise receive certain subsidies irrespective of the capacity payment received through FCM. Because OOM resources receive "out-of-market" revenue, these resources are offered into the FCA effectively as price takers, thus not reflecting a market-based or competitive cost of entry. OOM resources clear in the FCA on the basis of these low offers, and in so doing take the place of new or existing resources that offer in the FCA at competitive but higher prices. The result is an auction clearing price that is too low to retain or attract new or existing resources displaced by the OOM resources.

The existing APR is applied only when there is a need for new capacity and competitive new entry is prevented from setting the price because the amount of OOM capacity exceeds the amount of new capacity required. When these conditions are satisfied, the capacity price is adjusted after the auction to the lesser of CONE or the price at which the last in-market new capacity resource withdrew from the auction minus \$0.01. This price would then be paid to all resources. But, the large amount of excess supply has prevented the APR from being triggered, as no new capacity is required.

ISO-NE's two-tier pricing proposal would have administratively set a price (the "Alternative Capacity Price") that would have prevailed if the OOM resources had submitted competitive offers into the FCA – that is, the price that would have prevailed if these resources did not receive OOM revenues and had offered into the FCA at prices reflecting their full cost of entry. Thus, the FCA would clear based on the higher offers of resources displaced by the OOM resources. In essence, the Alternative Capacity Price is a "but-for" price – a price that would have cleared the FCA "but for" the OOM resources. This "but-for" price would have been paid to: (a) all existing resources that clear the FCA; and (b) resources that did not clear the FCA, but do clear when OOM resources are re-priced (referred to as "in-between" resources).

The second price under the ISO-NE proposal consists of the "regular" (and lower) FCA clearing price calculated with the OOM resources in the FCA as price-takers. Under the ISO-NE proposal, this "regular" FCA clearing price would have been paid to new OOM resources and new in-market resources; in other words, all resources not paid the "but-for" price above.

For each annual auction with OOM resources, ISO-NE would have calculated an Alternative Capacity Price as if the OOM MW had offered competitively into the FCA. The ISO-NE internal market monitor would calculate competitive offers for OOM resources based on resource-specific cost benchmarks, and these benchmark offer levels would be entered for the OOM resources. The higher-priced offers would result in an Alternative Capacity Price that would be higher than the FCA clearing price because the OOM resources have been "re-priced" in the auction at their higher, competitive offer levels.

In the April 13, order, FERC generally agreed with the principles underlying ISO-NE's two-tiered pricing model. In particular, FERC strongly agreed with the use of benchmark pricing as determined by the ISO-NE internal market monitor for setting competitive offer levels for OOM resources.

However, FERC disagreed with the ISO-NE proposal's effective outcome of purchasing capacity in excess of the ICR in order to allow all OOM resources to clear. Under the ISO-NE proposal, customers would purchase all new capacity offered below the "regular" FCA clearing price and all existing capacity offered below the "but-for," Alternative Capacity Price, resulting in the total amount of capacity purchased exceeding the ICR. FERC found that ensuring that total purchases do not exceed the amount required for reliability (the ICR) is a "bedrock

IMPLICATIONS OF ORDER

FERC has once again demonstrated its commitment to control buyer-side market power in the Northeast capacity markets. After implementing important buyer-side mitigation mechanisms in New York and (most recently) in PJM, FERC turned its attention to New England and essentially ordered to region to implement a framework similar to its neighbors to the south and west.

The stakeholder process to develop an offer-floor mitigation mechanism will be contentious and controversial. FERC directed that ISO-NE make a compliance filing by May 13, 2011 with a schedule for the stakeholder consideration as well as the filing of market rules required by the order.

The April 13 order sends conflicting signals regarding the future trajectory of New England capacity prices. On the one hand, the use of benchmark prices for new resources designated as OOM will have a long term bullish impact on auction clearing prices, as these resources would not be able to depress auction clearing prices as we have seen in past auctions. Moreover, the more granular zonal modeling mechanism should improve the locational aspects of the FCM. One of the principal failures of the market has been its lack of locational price separation despite the rejection of hundreds of MW of resources seeking to de-list but precluded from doing so for reliability reasons. FERC's approval of ISO-NE's proposal is a step in the right direction to address this shortcoming in the existing framework.

But, the fact remains that the New England market is awash in excess capacity, and it will be many years before this surplus is "eaten up" by load growth or retirements. The floor price provisions will go away concurrent with implementation of an offer-floor mitigation mechanism, so the earlier this mechanism is implemented the more likely that auction clearing prices will collapse to very low figures. In addition, FERC's refusal to apply mitigation to the thousands of MW of historical OOM in the New England market means that this capacity will continue to be treated as price-taking, existing resources. Furthermore, demand resources continue to deeply affect capacity prices in New England, and the revised mitigation construct (depending on its final form) could still result in low prices should demand resources deemed as OOM capacity be re-priced at relatively low values to clear in the auctions.

The precise details of the to-be-developed offer-floor mitigation mechanism will have a major impact on developing an FCM outlook. We can, however, make certain assumptions to guide our outlook, as discussed above.

Controversy over Retirement Requests

Earlier during the FCA5 qualification period, Dominion submitted permanent de-list bid requests for all four Salem Harbor units to exit the auction (a total of 749 MW). However, ISO-NE's Internal Market Monitor rejected the permanent de-list bids on the basis that the de-list offer prices did not reflect the long run average cost of the resource (net of expected non-capacity revenue). Dominion responded by submitting a non-price retirement request effective June 1, 2014 (the start of the FCA5 commitment period) for all four Salem Harbor units. Under the FCM market rules, non-price retirement requests are specifically designed to address units seeking to retire and permanently exit the FCM.

ISO-NE is reviewing the Salem Harbor non-price retirement request to determine the impact on system reliability; as a result, ISO-NE could determine that the Salem Harbor units are needed for reliability and reject the retirement request. Such rejection would lead to a reliability agreement between ISO-NE and Dominion, under which the Salem Harbor units would be compensated on a cost-of-service basis. ISO-NE is expected to announce the results of its Salem Harbor reliability review by May 10. While significant transmission investment has been put in place in the NEMA/Boston zone (and more is planned through 2014), ISO-NE may very well find that the units must remain in service to assure system reliability in the region, particularly if transmission upgrades or other capacity resources are not in place by June 2014.

Separately, it is interesting to note that Entergy did not submit any de-list bids or non-price retirement requests for its Vermont Yankee nuclear unit; thus, the unit remains in FCA5 as an existing capacity resource. As we have discussed in our publications, Vermont Yankee's operating license expires in March 2012 (though the unit is due for refueling this October) and the Vermont legislature has refused to consent to an extension. Meanwhile, the U.S. Nuclear Regulatory Commission (NRC) has approved a 20-year extension of the unit's operating license and Entergy has sued the state of Vermont, setting up a confrontation between state and federal jurisdiction over the future of the nuclear unit.

During FCA4, Entergy submitted a dynamic de-list bid for Vermont Yankee of \$3.933 per kW-month; however, ISO-NE rejected it for reliability reasons. In approving the FCA4 results, FERC approved ISO-NE's decision to keep Vermont Yankee in service and directed that Vermont Yankee be compensated its de-list bid (\$3.933 per kW-month) for the 2013-14 capacity year. As it did in the last auction, Entergy could submit a similar dynamic de-list bid during FCA5, knowing that ISO-NE likely would reject it for reliability reasons. Ultimately, however, Entergy's dynamic de-list bid would result in a capacity payment for Vermont Yankee that is above the auction clearing price.

The January 28 FERC order regarding the New York demand curve reset process had significantly bullish implications for New York City capacity clearing prices. FERC did not approve the NYISO proposals for several very significant determinants in the developing the New York City demand curve parameters, including the treatment of tax abatement and excess supply. This issue of *Capacity Watch* focuses on an assessment of the NYISO response as presented in their March 29 compliance filing.

Recent changes to 2011 installed reserve requirements have also affected the New York Rest of State and New York City outlooks. The New York Rest of State installed reserve margin requirement dropped from 18.0 percent to 15.5 percent, with bearish implications for the Rest of State market. In contrast, the New York City locational capacity requirement increased from 80.0 percent to 81.0 percent and is moderately bullish for Zone J capacity prices.

For details about the impacts of the installed reserve requirements and mitigation issues including Bayonne and Astoria II, please refer to the January issue of *Capacity Watch*.

NYISO RESPONSE TO FERC ORDER IS BULLISH FOR NYC

On January 28, 2011, FERC issued an order accepting some portions of the NYISO demand curve reset filing¹ and disallowing others. FERC ordered several changes to the NYISO cost of new entry (CONE) calculations, including a revision to the excess capacity assumptions, exclusion of the tax abatement from the New York City (NYC) CONE, and inclusion of deliverability costs (including interconnection costs).

As one of the key parameters involved in the construction of the New York capacity market demand curves, CONE is evaluated every three years pursuant to the NYISO capacity market rules. Net CONE (the gross cost of new entry minus energy and ancillary revenues) sets the reference price at 100 percent of the installed reserve margin requirement. The demand curve slopes downward to the right from the reference point until it reaches zero (at 18 percent surplus for NYC and LI; 12 percent for ROS). Any significant changes to net CONE will have implications for future capacity clearing prices.

ESAI's estimate of the New York City demand curve reference point (based on net CONE) increased significantly as a result of the FERC order. NYISO proposed a reference point of \$16.91/kW-mo, however, ESAI estimated that the impacts of the FERC order would increase the reference point to \$32.95/kW-mo, nearly a 100 percent increase over the NYISO proposed reference price. NYISO's compliance

¹ New York Independent System Operator, Inc., 134 FERC ¶ 61,058 (2011) ("January Order"), January 28, 2011, Docket No. ER11-2224-00.

filing² accepts some of the FERC-ordered changes but proposes changes to others. Overall, the compliance filing retains most of the bullish impact of the FERC order and results in a newly-proposed reference point of \$30.00/kW-mo, only 10 percent below our original estimate.

A summary of the NYISO compliance filing in the context of the FERC order is provided below.

Overview of March 29 NYISO Compliance Filing

The January 28, 2011 FERC responded to the November 26, 2010 NYISO tariff filing³ to revise the demand curve parameters for the three capability years starting May 1, 2011. The specific issues addressed in the FERC order as well as the FERC directives and their impacts are summarized below (impacts will be summarized separately):

1. Deliverability Costs and NYC SUF Costs

Rest of State Deliverability Costs

In its November filing, NYISO excluded deliverability costs from the CONE calculations. The NYISO's position has been that any upgrade costs incurred by a generator to be deliverable to the system are specific to the generator. (To receive capacity payments, generators must be deliverable to all parts of the locational capacity area in which they are located. In the Rest of State region, generators in the west and north are not necessarily able to be 100 percent deliverable to the Hudson Valley due to constraints on the UPNY/SENY interface.)

In its January 29 order, FERC maintained that deliverability and interconnection costs are an integral part of the cost parameters for a generation developer and ordered that these costs be included in the CONE calculations for the demand curve reset.

In response, NYISO performed a full deliverability analysis⁴ that covered each of the New York deliverability areas. NYISO determined that no system upgrades would be required and that each of the peaking units that were tested was fully deliverable to the system. As such, NYISO confirmed that no deliverability costs were required for inclusion in the CONE assessments, consistent with their original filing.

² New York Independent System Operator, Inc., Compliance Filing and Request for Flexible Effective and Implementation Dates, Docket No. ER11-2224-00_ Implementation Dates, Docket No. ER11-2224-00.

³ New York Independent System Operator, Inc., Tariff Revisions to Implement Revised ICAP Demand Curves for Capability Years 2011/2012, 2012/2013 and 2013/2014, Docket No. ER11-2224-000, November 26, 2010.

⁴ Affidavit of Steven Corey, attachment to NYISO March 29, 2011 filing.

In our January *Capacity Watch* assessment, ESAI included costs from the NYISO consultant's report that indicated that inclusion of deliverability costs would increase net CONE in ROS by \$26.95/kw-yr. ESAI had included this deliverability cost in the previous ROS demand curve assessments and capacity clearing price forecasts.

New York City

NYISO also provided a revision to the assumed System Upgrade Facility (SUF) costs as a result of the FERC order. NYISO's November proposal included an SUF cost allocation of \$3.1 million in its assessment of CONE. After further review, NYISO has revised the SUF cost allocation to \$14.5 million, an increase of \$11.4 million.

NYISO noted in its compliance filing that this revision had the impact of increasing the reference point by 5.1 percent⁵ or approximately \$0.90/kW-mo. This value was very close to the assumption that ESAI utilized in our last outlook of \$1.06/kW-mo derived from a \$43/kw capital cost adder⁶.

2. Tax Abatement - NYC

On August 3, 2010, prior to finalizing the 2010 demand curve reset process, the City of New York (NYCEDC) revised the Uniform Tax Exemption Policy (UTEP) to incentivize new peaking generation in the city through a discretionary property tax abatement. As a result of this new UTEP tax exemption policy, NYISO excluded property taxes from the CONE determinations for New York City. FERC subsequently ruled that the UTEP tax exemption is not just and reasonable because it is discretionary and not a right as previously provided for under the ICIP program.

FERC ordered that the full property tax costs be included in the CONE calculation for the New York City proxy peaker. NYISO's compliance filing indicates that NYISO will now include the full impact of New York City property taxes in its CONE assessments.

The inclusion of the property tax in the CONE assessment results in an increase in the reference price of over \$9.00/kW-mo.

3. Excess Capacity Level Assumptions

The revenues associated with the proxy peaker are defined by the prevailing market conditions defined in the analysis. The most appropriate indicator of market conditions is the amount of excess capacity supply. Greater capacity supply translates into lower energy revenues and also lower capacity revenues obtained over time. In its November filing, NYISO proposed surplus capacity levels at 1.0%

5 Affidavit of David Lawrence, attachment to NYISO March 29, 2011 filing.

6 Protest of the New York City Suppliers, Docket No. ER11-2224-000, December 21, 2010

INTRODUCTION

California has officially committed itself to producing 33% of its electric consumption from renewable sources by 2020, and the ISO has committed itself to further restructuring its markets to more effectively integrate large amounts of intermittent generation and appropriately allocate the costs of doing so. The latest generation interconnection cluster apparently produced hundreds of applications and was followed by another generator interconnection reform initiative.

RPS LEGISLATION

Governor Brown signed legislation into law which commits all California “retail sellers of electricity” to obtain 33% of total retail sales of electricity from renewable sources by 2020. The legislation will supplant the 33% renewable energy standard previously instituted by executive order by Governor Schwarzenegger in 2009. While extending the official 20% requirement from 2010 to 2013 and adding a 25% benchmark by the end of 2013, the legislation eliminates the flexible compliance rules which provide an additional three-year window to make up for shortages in the 2010 deadline. By January 1, 2012, the CPUC will be required to establish the quantity to be procured by each retail seller for the compliance periods. The requirements would also be applied to publicly-owned utilities with enforcement done by the Air Resources Board (ARB) and California Energy Commissions (CEC). Other highlights of the legislation include:

- The CPUC is required to approve utility-owned renewable generation of up to 8.25% of sales if it “provides comparable or superior value to rate-payers when compared to the recent contracts.”
- Provides a preference and minimum percentage for new contracts with renewable facilities located in California (50% before 2014, 65% from 2014 through 2016 and 75% thereafter)¹, facilities that have a first point of interconnection with a California Balancing Authority Area (BAA), facilities that can schedule actual output into California BAAs, or facilities with an agreement to dynamically schedule into a California Balancing Authority.
- Limits REC-only transactions to 25%, 15% and 10% in the same periods. The remaining balance could be met with “firmed and shaped” resources.
- Requires the CPUC to report to the legislature annually on costs and savings associated with purchase of renewable generation, costs and savings from IOU incentives paid for distributed and renewable generation, etc.
- Requires CPUC to issue a decision within 18 months on CPCN applications.

¹ Percentage applies to total renewable portfolio – not just increment – excluding contracts executed before June 1, 2010.

- Establishes criteria for “municipal solid waste conversion” limited to converting “solid waste to a clean-burning fuel for the purpose of generating electricity.”
- Requires CEC to determine whether run-of-river hydro in BC should qualify for RPS.

The legislation provides no real game changers from current requirements. The limitation on the use of RECs will require more generation in or near California and will favor other non-intermittent out-of-state generation that can be dispatched (e.g., geothermal or biomass). By replacing the prior executive order, the legislation makes reversing the policy more difficult.

GENERATOR INTERCONNECTION

As California’s renewable energy gold rush continues unabated, the CAISO is looking at some 200 interconnection applications received in its #4 Cluster Window which closed on March 31 and was the primary opportunity to get an interconnection study started this year. The IOUs’ wholesale distribution queues received over 100 applications as well. With the Renewable Auction Mechanism (RAM) program and IOU solar PV solicitations, many of these applications are expected to be 20 MW or smaller. The ISO does not expect to make an updated list available until sometime in May. In the meantime, the ISO has initiated another in what is expected to be an annual Generator Interconnection Process reform – GIP 2. Renewable generator interconnection has also become an integral part of the ISO’s annual Transmission Planning Process (TPP).

GIP 2

The ISO has identified 24 topics which will be considered in this year’s generator interconnection process update. The plan is to file any tariff changes with FERC by October 1. Most of the topic areas are process refinements, though a few are policy related. The most significant proposed reform is an economic test and cost allocation for network upgrades associated with generator interconnections. The ISO’s straw proposal would change the current FERC policy that the cost of all transmission network upgrades financed by interconnecting customers (ICs) be refunded over five years. The ISO proposes to identify and approve transmission upgrades primarily through the TPP, relying on anticipated resource portfolios – developed in collaboration with the CPUC and other regulatory authorities – to determine the network upgrades that will be needed to interconnect new generation. The TPP would incorporate Phase 2 cluster studies, adjust the resource portfolios based on the cluster study results, and develop a transmission expansion plan that most cost-effectively meets the identified policy requirements. Approved network upgrades would be built as rate-based transmission without further IC funding. The IC would have to pay for network upgrades for generator interconnection (not included in the TPP list) without a future refund. Instead, they would receive Congestion Revenue Rights (CRRs) for the capacity increase resulting from the

ESAI evaluates individual projects through development and construction and then projects the probability of completion and start-up dates under its Project Evaluation Program (PEP). The projects are then compiled to provide a forecast of new capacity for each year in each of the three Northeast Control Areas. A spreadsheet provides details of each project and is available for specific clients. This spreadsheet can be downloaded from the ESAI website. An abbreviated sample of the spreadsheet is provided below.

ESAI continually updates the PEP as new information becomes available that would affect the timing or probability of completion of a project. ESAI incorporates a wide array of source information to develop an assessment of the likelihood of a project moving forward to completion including:

- Industry Network of Contacts
- Government Agency Contacts
- Financial Community Contacts
- Filings with Transmission Authorities
- Filings with Siting Commissions
- Environmental Permits and Filings
- Municipal Planning, Zoning & Inspector Contacts
- Other; Media & Corporate Relations

These sources, combined with ESAI’s in-house expertise, allow ESAI to provide its clients with detailed and accurate information. ESAI closely follows changes in permitting and siting status and makes adjustments whenever necessary. ESAI also monitors funding qualifications – a key development in the post-Enron environment. The following pages provide a recap of the updates as well as the summarized projections for each Control Area.

ESAI		PROJECT EVALUATION PROGRAM						
		 High Confidence	 Unconfirmed	 Withdrawn	 Online	 Retirement		
PJM Projects	Developer	Pricing Zone	Fuel Type	Capacity (MW)	Peaker (1)	Probability of Completion	Estimated In-Service Date	Year
North Allegheny Wind Farm	Duke Energy	PENELEC	Wind	70		100%	Oct-09	2009
Top Crop Phase 1	Horizon Wind Energy	COMED	Wind	102		100%	Oct-09	2009
Linden VFT	GE	PSEEG	VFT Transformer	(300.00)		100%	Nov-09	2009
Stonycreek Wind	E.ON	PENELEC	Wind	52.5		100%	Nov-09	2009
Armenia Mountain Wind	AES	PENELEC	Wind	186		100%	Dec-09	2009
Lee-DeKalb Wind Energy Center	NextEra Energy Resources	COMED	Wind	217.5		100%	Dec-09	2009
Calvert Cliffs Unit 2 Uprate	Constellation Energy	PEPCO	Nuclear	10		100%		2009
Fowler Ridge Wind Farm Phase II	BP/Dominion	AEP	Wind	200		100%	Dec	2009
Susquehanna Uprate Unit 1	PPL	PPL	Nuclear	159		100%	Jun	2010
Cayuga Ridge South Wind Farm	Iberdrola Renewables	COMED	Wind	300		100%	Mar	2010
Calvert Cliffs Unit 1 Uprate	Constellation Energy	PEPCO	Nuclear	10		100%	Q3	2010
North Anna Uprate Unit 1	Dominion	DOM	Nuclear	14		100%	May-10	2010
North Anna Uprate Unit 2	Dominion	DOM	Nuclear	58		100%	Jul-10	2010
Beech Ridge	Invenergy	APS	Wind	100.5		100%	Sep-10	2010
Top Crop Phase 2	Horizon Wind Energy	COMED	Wind	198		100%	Oct	2010
York Energy Center	Calpine Corp	PECO	Nat gas	545		100%	Mar	2011
Big Sky Wind	Edison Mission	COMED	Wind	240		100%	Feb-11	2011
Criterion Wind Power Generating Facility	Constellation Energy	APS	Wind	70		100%	Feb-11	2011
Roth Rock Wind Energy Project	Synergics Wind Energy LLC	APS	Wind	50		100%	Jan-11	2011
LaSalle Uprate Unit 1 and 2	Exelon	COMED	Nuclear	26		100%	Mar	2011
Dresden	AEP	AEP	Nat Gas	580		100%	Q1	2012
Susquehanna Uprate Unit 2	PPL	PPL	Nuclear	159		100%	Spring	2011