BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning	)))))	R.04-04-003

OPENING COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON THE CALIFORNIA PUBLIC UTILITIES COMMISSION'S CAPACITY MARKETS WHITE PAPER

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The California Independent System Operator Corporation ("CAISO") commends the staff of the California Public Utilities Commission ("Commission") on its issuance of the Capacity Markets White Paper ("White Paper"). The White Paper identifies a number of very important issues that require resolution if California is to create a viable long-term resource program that supports appropriate investment in energy infrastructure.

As discussed in detail below, the CAISO does not endorse at this time any specific form of long-term resource adequacy program, be it a form of short-term capacity market as proposed by the staff, an alternative form of capacity market, or the "energy-only" structure advocated by certain parties. The CAISO recommends that the Commission first address certain fundamental questions - e.g., *what level of reliability are consumers willing to pay for?* - prior to deciding on a long-term resource adequacy structure.

It is important to emphasize that the CAISO's reluctance to agree, at this time, on the final form of a capacity-market based resource adequacy program should in *no way* be interpreted as equivocating on the resource adequacy structure already articulated by the Commission. Exigent circumstances demand that the Commission move forward and finalize the details of that program now so that a viable resource adequacy requirement can be in place no later than June 1, 2006. As originally established in the Commission's January 2004 order on resource adequacy, the CAISO supports a capacity-based approach, with reasonable accommodations for existing resources, for purposes of both quickly establishing what may well be a transitional resource adequacy program and ensuring that the CAISO has the necessary physical resources to reliably operate the system over the next few years.

Finally, the CAISO recommends that the Commission develop a clear timeframe for implementing the reforms necessary to implement a viable long-term resource adequacy program. A transition period will clearly be needed. As part of that consideration, the CAISO urges the Commission to work closely with the CAISO such that the necessary retail and wholesale market reforms can occur concurrently and complement one another.

I. INTRODUCTION AND SUMMARY

The staff's White Paper makes a significant contribution to the understanding of the rationale for capacity markets, the potential merits of implementing an organized capacity market, and the issues that must be properly addressed before such markets can even hope to achieve their stated objectives. The CAISO concurs with the Commission staff that the current structure of California's electricity markets is incapable of sustaining the level of resource adequacy consistent with the State's traditional reliability standards. This is an important acknowledgment, because it means that doing nothing is unacceptable. As the White Paper notes, long-run reliability can only be sustained by improving the current structure of the market or by carefully designing and implementing additional mechanisms to secure the revenues needed to support the appropriate level of infrastructure development. Indeed, a dual approach, pursuing both paths in parallel, may well be the wisest approach for California.

The staff's White Paper is particularly helpful in explaining the structural problems associated with today's electricity markets. The CAISO agrees that these structural defects are partly attributable to technical limits, such as the absence of real-time metering for many customers, and the inability to curtail specific customers when shortages occur. The State has made significant progress in addressing these shortcomings by installing interval meters for at least the larger customers, and more can be done to put these improved technical capabilities into effect, while extending similar capabilities to other customers.

The White Paper is also correct to point out that the structural problems are partly a function of specific policies that limit the ability of California's markets to function well and to provide the incentives and revenues necessary to support the appropriate levels of resource investment. As the White Paper correctly notes, two key policies contribute to these structural problems. The first is the use of bid caps and other measures that prevent energy and operating reserve market prices from reflecting the value of energy or reserves during periods of true supply shortages. The second is the use of rate designs that substantially disconnect retail rates from the short-run realities of wholesale spot prices and therefore discourage development of robust demand response programs. While correcting both sets of problems requires a careful transition to ensure that market power issues are properly dealt with, addressing both problems should be part of any State policy to ensure long-run resource adequacy. Neither reform can be fully effective without the other; a coordinated effort is therefore essential.

The CAISO is already in the process of reforming its wholesale market rules as part of its Market Redesign & Technology Upgrade ("MRTU") project. Among many other changes, the CAISO has already proposed, and FERC has approved, a transition mechanism for increasing the bid caps in the CAISO markets. Moreover, the currently proposed design already includes a form, albeit limited, of scarcity pricing. The CAISO anticipates the market design to further evolve subsequent to the initial implementation scheduled for February 2007 and recognizes the need to coordinate with the Commission to ensure that the wholesale and retail market designs complement one another.

The White Paper appropriately summarizes the difficulties and issues associated with designing and implementing effective capacity markets. To expand on this effort, the CAISO is attaching two complementary papers detailing the current ICAP mechanisms in the East and proposals to reform those ICAP mechanisms in PJM and New England: "ICAP Systems in the Northeast: Trends and Lessons" and "ICAP Reform Proposals In New England and PJM" (**Attachment 1** and **2**, respectively), are intended to be responsive to the Commission's request for comments on "Lessons Learned and Related Policy Questions." While related to and confirming many of the points raised in the White Paper itself, the CAISO believes that the attached documents provide necessary further detail and will enhance both the Commission's and stakeholders' understanding of the issues.

Capacity markets may well prove necessary in California, but given the well-documented difficulties in their design and implementation, the CAISO urges that at least equal attention be focused on correcting the policies that prevent California's current markets from effectively supporting adequate resource investments. These efforts should become a high priority for both the Commission and the CAISO, whether or not the State chooses to develop an organized capacity market, replete with auctions, demand curves, peak energy rental adjustments, availability metrics, and locational features. In this regard, the CAISO suggests that the Commission staff couple its final recommendations for any resource adequacy mechanism with a call for complementary reforms in Commission rate structures (e.g., retail tariff structures that complement the wholesale market design and facilitate the development of price responsive demand) that currently create certain of the "structural problems" and apparent need for capacity mechanisms in the first place. Moreover, as stated above, the reform of retail rate structures needs to be done in conjunction with the already established timeframe for reforming wholesale market rules. The CAISO's MRTU program will be implemented in February 2007. The CAISO believes this dual approach would put the State in a better position to make the fundamental policy choices it faces and to move eventually to a more sustainable resource adequacy structure.

Consistent with this dual approach, the CAISO specifically cautions the Commission staff not to move prematurely to a recommendation or endorsement of any particular capacity mechanism. While we agree with the Commission staff White Paper on many of the "lessons learned" (see further comments below) from the experience of eastern ISOs in developing capacity mechanisms, it also appears that the eastern ISOs have paid insufficient attention to addressing their own "structural problems" and to the possibility that the resource adequacy problem could be managed more effectively without an explicit capacity construct.

Our view is that the "energy-only" market has not been adequately defined or examined, but rather has simply been dismissed out of hand without exploring whether the issues that make this approach seem problematic could be addressed and resolved more easily than the issues that must be addressed in any capacity framework, no matter how well designed. The CAISO is *not* endorsing for the long-term an energy-only approach or any particular capacity structure at this time. However, to ensure that this alternative is more fully considered by the Commission and the CAISO, we have also commissioned a paper by Dr. William Hogan to further develop and explain what an energy-only approach might look like. **Attachment 3**, entitled "On an 'Energy-Only' Electricity Market Design for Resource Adequacy." In addition, this paper cites to "Energy-Only" proposals under consideration in the Midwest ISO ("MISO") and Texas ("ERCOT") markets. For ease of reference, the CAISO has included these proposals as **Attachments 4** and **5** to these comments. Even if the State decides to implement some type of capacity mechanism, the CAISO believes that a better understanding of the energy-only approach will assist the State in understanding the issues that must be addressed in any resource adequacy approach.

If a capacity mechanism proves to be necessary, the CAISO recommends that more attention be paid to a range of alternative capacity mechanisms. As we discuss further below, the CAISO agrees with the Commission staff that there are various features of the New York and New England approaches that appear promising; a best practice model from these approaches may well prove to be a workable method for the State, and refinements to address specific California issues could ultimately improve the approaches developed by the eastern ISOs. However, while short-run capacity markets are not new, they too remain largely unproven as to whether they will be effective mechanisms to induce the desired level, type and location for resource investment.

Hence, the CAISO is not yet prepared to agree that a short-run (monthly) capacity auction mechanism with a downward sloping demand curve – the ISO-NE approach -- is inherently preferable to the PJM approach, which includes a four-year forward auction and also includes a sloping demand curve. Now that the PJM proposal has been submitted to FERC with additional details (see Attachment 2), California has an opportunity to examine this approach more thoroughly before the Commission endorses a specific capacity mechanism. There are important tradeoffs between a short-run approach and a long-run, forward auction approach that should be fully understood, and there are variations of both approaches that may be worth considering and should at least be well understood before the State concludes that a specific mechanism is the best choice.

The CAISO is fully prepared to work closely with the Commission in evaluating these various alternatives. Once a choice is made, the CAISO understands that it will have a major role to play in developing many of the details of any resource adequacy mechanism. If the approach includes an explicit capacity auction mechanism with a "demand" curve reflecting both reliability targets and investment requirements, the CAISO assumes that, like its counterparts in the East, the CAISO will have a primary responsibility for designing and implementing many of its features. At the same time, it will be vitally important for the Commission to indicate clearly what the resource adequacy target is – i.e., define how much reliability consumers should be willing to pay for -- so that the CAISO can ensure that the resource adequacy mechanism ultimately adopted not only to meet that goal, but also achieves it at the lowest cost. In this vein, the CAISO expresses its continuing support for the Commission's effort and its commitment to work cooperatively with the Commission, its staff, and all affected parties.

That said, the CAISO recognizes the exigency created by the need to ensure harmony between the CAISO's current and ongoing efforts at market reform, embodied in its MRTU project, and the Commission's imminent ruling in its ongoing resource adequacy proceeding. As recently articulated by the FERC, the elements of the CAISO's approved conceptual MRTU design assumes certain attributes of the State's resource adequacy plan, including, most importantly, the ability to provide the CAISO with sufficient available resources and capacity to ensure grid reliability.[1] The CAISO believes that the Commission's substantial efforts in developing a transitional, capacity-based resource adequacy program intended for implementation in 2006 can satisfy the FERC's expectations. The cornerstone of the transitional program's ability to ensure near-term grid reliability is adoption of the CAISO's proposed local capacity requirement. The local capacity obligation serves the objectives of resource adequacy in the near-term transitional period by addressing the units most at risk of retirement or mothballing and by accommodating any interim eligibility of certain existing contractual supply arrangements that may not be wholly compatible with the CAISO's MRTU residual unit commitment process. Clearly, over the next several years, until the State has fully evaluated the various mechanisms and reforms to achieve resource adequacy, it will be necessary and appropriate to establish a transitional program, which includes locational requirements.

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[1] *Order on Rehearing,* 112 FERC ¶ 61,310 (Sept. 19, 2005) at P.51.

Further, as part of that transition, the CAISO continues to support long-term contracting by load-serving entities to support new resource investment. Such contracts may, by necessity, need to be five to ten years in length in order to support the capacity investment needed to serve load over the next several years. For purposes of facilitating such contracting, the CAISO urges the Commission to remain flexible and consider appropriate allocation mechanisms whereby the costs of such contracts are equitably allocated to all load-serving entities that benefit from the addition of such resources. Moreover, the Commission should consider mechanisms to protect the customers of a particular entity from cost shifts should some of that entity's customers switch suppliers in the future.

In its comments below, the CAISO provides more detailed responses to the specific issues listed by the Commission staff:

(1) Lessons Learned and Related Policy Questions;

(2) Staff's recommendations;

(3) Appropriate roles and responsibilities of the Commission and the CAISO in the development, design, and potential implementation of capacity markets in California; and

(4) Other significant issues.

The CAISO fully acknowledges and appreciates the need to move forward expeditiously to address these issues. The CAISO recommends that all potential solutions and avenues be explored at some consistent level of examination. It is important to note here that the CAISO does not yet have a formal or final position or recommendation regarding capacity markets or any alternative thereto. The CAISO intends to develop such a recommendation over the next several months, hopefully informed by both stakeholder comments and those received in response to the Commission staff's White Paper.

II. RESPONSES TO QUESTIONS SET FORTH IN THE WHITE PAPER

1. Lessons Learned and Related Policy Questions

The White Paper correctly references a number of the "lessons learned" from the PJM, New York and New England Installed capacity or "ICAP" markets. As explained in the White Paper (pp. 35-36), PJM experienced a number of problems with its ICAP market including: 1) the original availability mechanism, which created incentives for ICAP suppliers to "de-list" during critical summer days/hours when energy prices in other regions were more attractive; 2) capacity price volatility and related market power concerns; and 3) the lack of a locational capacity requirement and the resultant under-development of resources in certain areas of their system.

As stated in the White Paper, New York ISO reports to FERC indicate that the prices and revenue streams in its capacity markets have stabilized (White paper at 34). In addition, the White Paper notes that the demand curve has resulted in a reasonable price for capacity (Id.).

With respect to the New England markets, the White Paper states that the lack of a locational requirement has resulted in a "dramatic increase in the number of reliability agreements," (Id. at 37).

In summary, the White Paper identifies the following lessons learned and policy questions from the Eastern markets (Id. at 38-39):

Lessons Learned

1. A vertical demand curve causes unwanted volatility in revenues, and exacerbates market power in the capacity market. A sloped demand curve mitigates these problems.
2. Capacity markets should use locational resource targets that account for transmission constraints.
3. Bilateral capacity markets should be accompanied by a centralized market that accommodates smaller LSEs. This does not interfere with bilateral contracting and can increase the efficiency and reduce the market power in bilateral markets.
4. The ICAP demand curve should account for peak energy-market revenue.
5. Capacity should not be defined as name-plate capacity, but should be adjusted for performance.
6. The demand curve should be designed so the fixed-cost recovery is somewhat above normal when installed capacity is short of the target adequacy level and below normal when installed capacity is above this level.

Policy Questions

1. Would a downward sloping demand curve capacity market construct, similar to the New York approach, be an appropriate mechanism to support California's resource adequacy program?
2. Would a capacity market, such as in New York, assist LSEs to make adjustments by being able to sell excess capacity or buy it when they are short?
3. Would this mechanism assist California in meeting its goals to be resource adequate and reach a minimum of 15-17% reserve margins?
4. To address deliverability concerns and the meet the ISO's requirements, is it appropriate to investigate solutions for local areas as a first step?

5. Do capacity markets in local areas that are designed with downward sloping demand curves significantly mitigate market power concerns? What are the other appropriate steps (e.g., subtraction of peak energy rents)?

CAISO Comments on Lessons Learned

The CAISO largely concurs in the lessons learned identified in the White Paper. As summarized on p. 70 in “Trends and Lessons”, the early ICAP markets in PJM and New England have several limitations, including:

- *Deliverability Tests*: Because ICAP providers are paid the same regardless of their location, ICAP markets need rules to provide locational incentives.
- *Availability Standards*: Because ICAP providers are paid whether they run or not, standards are required for availability levels and timing.
- *Conservation Incentives*: ICAP requirements keep extra capacity in operation. As a result, energy prices do not reflect the full cost of capacity.
- *Market Power*: The potential for the exercise of market power in long-run ICAP markets is constrained by entry. Entry and exit, however, do not constrain daily ICAP process and retail competition leads to daily changes in ICAP requirements.

As noted both in the White Paper and in our attachments, “Trends and Lessons” and “ICAP Reform Proposals,” these deficiencies in the early ICAP designs can and are proposed to be fixed by, respectively, introducing locational ICAP requirements, moving from Unforced Capacity or “UCAP” systems to a “reserve shortage hours” availability metric (in New England), using forward auctions that allow new entry, demand-side resources and transmission upgrades to compete against existing capacity (in PJM), and administrative demand curves for achieving the target level of reserves (in both ISOs).

However, as noted in “Trends and Lessons” (at 71), and a point on which the CAISO concurs, none of these solutions or fixes provide fully efficient incentives. For example, the practical effect of capacity market mechanisms is to reduce the effective price of energy and thus, to a certain extent, the effectiveness of incentives for demand response. The CAISO urges the Commission to carefully consider this issue, especially as it relates to the State’s “loading order” for resources, as codified in the Commission-adopted Energy Action Plan (“EAP”) II. EAP II states that an explicit objective of the sponsoring State Agencies is to facilitate the development of demand response in California (EAP II at 2, 4-5). While the development and deployment of appropriate supporting retail tariffs and real-time metering are a necessary prerequisite, one must question the effectiveness of such programs if the true cost of power is unrevealed and, in part, hidden in the capacity payments inherent in a capacity market construct.

Market Power

With respect to limiting the exercise of market power, in contrast to long-term markets, entry to and exit from the market do not constrain prices in short-term capacity markets. As explained in the White Paper, the introduction of an administrative demand curve for capacity can reduce the expected profits from an exercise of market power in the capacity market, but it cannot fully prevent market power from raising prices. Other measures are therefore necessary, such as offer mitigation (in the PJM proposal) or counting all capacity, whether offered or not, to determine prices (in the New England proposal).

Impact on Bilateral Markets

With respect to the impact on bilateral markets, the CAISO generally concurs that short-term capacity markets can provide greater transparency (with respect to price formation) and act as a de facto cap or benchmark on the price in the bilateral market.

Accounting for Energy Market Revenues

The CAISO agrees with the White Paper that any form of capacity market should account for peak energy market revenues. If a primary driver behind the creation of a capacity market is addressing the “missing revenues” in the capped energy and operating reserve markets, the CAISO agrees that net market revenues from these markets should be accounted for when designing or determining compensation levels in a capacity market. The CAISO therefore recommends that not only energy market revenues, but also ancillary service market revenues be accounted for when determining overall revenues in the market.

In addition, the CAISO agrees that accounting for such revenues can mitigate incentives for suppliers to exercise market power and thus drive up the price of energy. However, the manner of implementation of this feature is critically important. As noted in “ICAP Reform Proposals” (at 45), New England originally proposed to calculate the peak energy rentals or “PER” monthly, after the fact, and then apply that month’s adjustment to that same month’s LICAP payment. That approach would create a direct correlation between higher prices in the energy market during a month and the PER adjustments for capacity payments for that month. However, New England subsequently modified its proposal to base the PER adjustment on the average PER for the previous 12 months, thus breaking the direct month-to-month connection or at least spreading out the effect over many months. The CAISO, thus, recommends that the Commission, should it ultimately recommend implementation of a capacity market proposal similar to that proposed by New England, be mindful of this issue before assuming that any PER adjustment mechanism will fully discourage market power in the energy markets.

The manner by which the crediting of other market revenues is achieved is a critical issue that will have to be carefully considered when the design details are discussed. In both PJM and New York, energy and ancillary service market revenues are accounted for when establishing the demand curve for reserves. In contrast, New England subtracts the energy market earnings of the "benchmark" or "Reference" unit from its actual LICAP payments to suppliers ("ICAP Reform Proposals" at 54-55). The two approaches are meant to achieve a similar effect, but the effects on market power and other incentives may differ.

Performance Adjustments and Availability Metrics

The CAISO agrees with the Commission staff that any form of capacity market must provide appropriate incentives to encourage generators to make their plants available in those hours in which their capacity is most valuable, as when the system is short on operating reserves. The CAISO is not convinced that the "Unforced Capacity" or "UCAP" methodology that is currently applied in the Northeastern markets is sufficient for this purpose. A UCAP system creates some incentive for suppliers receiving capacity payments to minimize forced and maintenance outages (See "Trends and Lessons" at 29-31). However, as noted in "Trends and Lessons" and "Reform Proposals," UCAP measures availability on an average basis and thus does not take into account the fact that capacity is far more valuable during shortage hours than in non-peak hours. For this reason, it is necessary for UCAP systems to be accompanied by significant penalties for failing to follow dispatch instructions. In addition, under a UCAP system suppliers may be reluctant to declare forced outages – and thus rely on the system – because such outages will impact their capacity revenues.

As further explained below, an important design issue must be the development of rules and incentives for capacity market suppliers to make their resources not only generally available, but available during critical peak periods when their power is most needed. The CAISO discusses this further below.

<u>CAISO Comments on Related Policy Issues</u>

Most of the "Related Policy Issues" identified in the White Paper pertain to whether a demand curve-based capacity market, such as that in place in the New York market and as proposed in New England and PJM, can be applied and used to satisfy California's resource adequacy requirements. As stated above, the CAISO generally concurs that such a market, appropriately constructed, could be applied in California and would:

1) provide a means for all load-serving entities – both large and small – to satisfy their resource adequacy obligations;

2) ensure that the costs of ensuring resource adequacy are appropriately allocated to all load-serving entities; and
3) partially mitigate the exercise of market power in the capacity market.

However, the CAISO believes that other features of the market design may be equally if not more important, including: 1) as noted in the White Paper, the subtraction of peak energy rents; and 2) the manner by which the price of capacity is set in the market, e.g., New England counts *all*, not just bid, installed capacity in the region when determining where the supply and demand curves cross, whereas New York and PJM determine the price of capacity in the market based on supply offers. The CAISO also believes that locational capacity requirements are an essential ingredient to any capacity market design.

Nevertheless, the CAISO cautions that it is premature to conclude that any short-term, demand-curve based, capacity market is the best means to ensure that California is resource adequate. Given the current level of regulatory uncertainty, multi-year commitments may be necessary to support needed infrastructure development in California. While a short-term capacity market may assist in that endeavor by providing a transparent short-term (spot market) price for capacity, it may not be sufficient in and by itself in supporting long-term investment in the absence of strong regulatory assurances that the mechanism will be allowed to work and left in place over several years.

The CAISO refers to the extensive discussion in "ICAP Reform Proposals" regarding PJM's new "Reliability Pricing Model" or "RPM" (at 47-62). As indicated there, one of the drivers behind development of the RPM proposal is to hold a resource adequacy auction four years in advance of need so as to support new resource development (generation, transmission, and demand-side resources).

Other Important Policy Issues

The CAISO recommends that the Commission carefully consider the following other important policy issues:

1) *Timeframe & Planning Horizon* – The White Paper focuses on a short-term capacity market like that in place in New York and proposed in New England as a solution to California's resource adequacy requirements. The White Paper dismisses longer-term approaches as "untested, need considerable more design effort and their mechanism is less transparent." (White Paper at p.26). The Commission should re-examine this presumption with a particular focus on determining the appropriate timeframe or planning horizon for a capacity market. As noted in both "Trends and Lessons" and "ICAP Reform Proposals," both the New York and New England capacity markets are short-term capacity markets. In contrast, PJM is proposing to run a series of auctions extending out four years. Most parties involved in the California resource adequacy dialogue over the last few years have acknowledged that a long-term requirement

is appropriate – if not necessary – to support needed investment. While the White Paper may be correct that such mechanisms are untested and are potentially complex, if a long-term program is necessary to attract and support investment, such approaches should not be dismissed out of hand**.**

One important factor to consider when evaluating this issue is the role of the central procurement agent, assuming there is one. While continuation of an LSE-based resource adequacy program is possible, there appears to be little support for this approach after considering the risks, rewards and incentives for load-serving entities to enter into long-term resource adequacy contracts. Considering the uncertainties surrounding load growth, load migration, and the evolving grid topology, most load-serving entities have expressed reservations about entering into long-term arrangements. Placing the CAISO, for example, in a long-term procurement role – albeit as an agent for load – complicates its independence and raises certain fundamental philosophical issues. The PJM RPM proposal raises similar issues.

As noted in "ICAP Reform Proposals" (at 1-2), the PJM proposal takes more of an "integrated planning and long-run acquisition" approach where the ISO itself decides what operational features (e.g., quick-start capability) to reward in the auctions it runs. In contrast, one design objective of New England's proposed LICAP market is to provide sufficient incentives and market signals to compel market participants to make choices that are aligned with the needs of the system operators. These are different philosophies and California must be clear, up front, as to which path it intends to go down.

2) *Integrated Planning* – Any resource adequacy program must work in conjunction with both transmission planning and any other integrated planning or procurement process. For example, the CAISO is advocating – and implementing – a proactive transmission planning process one purpose of which is to aggressively mitigate congestion hot spots on the grid. Such a process will clearly impact the suggested developments of local capacity requirements – defined by transmission constraints into and out of certain areas – and how such requirements change over time. Will and can load-serving entities enter into long-term commitments with existing or new resources to satisfy local capacity requirements the need for which may be mitigated through proactive transmission planning? Alternatively, as is proposed by PJM in its RPM proposal, should identification of transmission alternatives be actively sought and considered (integrated) as part of a long-term (four years in this case) resource adequacy program? Are these two approaches mutually exclusive? Both New England and PJM represent that their capacity market designs complement their transmission planning efforts.

3) *Consideration of Other Availability Limitations* – The White Paper correctly identifies the need to develop appropriate availability metrics, either based

on the established UCAP methodology in the Eastern markets and/or the reserve shortage hour availability metric propose in New England.

However, as noted in "Trends and Lessons" (at 31-46), these features are not adequate in addressing fuel availability limits and start-up conditions in particular. As explained in "Trends and Lessons" (at 46), "…resource availability under strained conditions depends on choices made by the resource owner, and resource owners will not incur the efficient level of costs to maintain availability if they realize limited returns from incurring those costs."

One important consideration is the need to complement any capacity market with a reserve scarcity pricing mechanism to, among other objectives, provide resource owners the necessary incentive to maximize the availability of their resources. For example, energy market prices can provide appropriate incentives for dual fuel operation.

As noted in "Trends and Lessons," the need to ensure that capacity and energy is available in stressed conditions is proceeding in different directions in 1) PJM (RPM), with continued reliance on UCAP; 2) New England (LICAP), combining locational ICAP and stronger availability metrics focused on paying capacity resources for performance when they are available during reserve shortage hours; and 3) New York, with greater reliance on shortage pricing in the energy and operating reserve markets.

Finally, the CAISO recommends that the Commission acknowledge and address energy limitations when considering capacity market structures. The unique hydroelectric-thermal resource relationship in California and the West requires that California validate that not only is sufficient *capacity* available to serve load, but that sufficient *energy* is also available. The number of resources in California with energy limitations (e.g., hydro or emission-limited resources) requires that we not only develop rules to ensure that resources are available during peak periods, but that resources appropriately allocate or ration their available energy over a given season or year.

4) *Transmission Rights* – Both PJM and New England propose to offer explicit transmission rights to complement their *locational* capacity market designs. As explained in "ICAP Reform Proposals" at pp. 35-37 and pp. 51-53, both PJM and New England will establish a separate demand curve and thus capacity price for each local area. Such an approach will result in different capacity prices for each area when the transmission constraints that define the area are binding. As a result of these price differences and the consequence that the price paid to generators in a local area may be different than the costs charged to load, both New England and PJM propose to allocate "Capacity Transfer Rights" (PJM term) to load. Capacity Transfer Rights are analogous to the financial transmission rights ("Congestion Revenue Rights") offered under the

CAISO's MRTU design. Such a design feature – Capacity Transfer Rights - may also be necessary in California.

2. Staff's Recommendations

As detailed in Section VI of the White Paper at 39-42, the Commission staff makes eight specific recommendations. Those recommendations are:

1) Adopt a short-run capacity market approach with a downward sloping capacity-demand curve for the CAISO;
2) Further investigate alternative availability metrics (e.g., UCAP v. ISO-NE's proposed metric based on performance during shortage conditions) and ensure development of an availability metric that is applicable to hydro, wind, thermal and other generation technologies, and to appropriate demand response products;
3) Consider subtraction of peak energy rents from the capacity payment;
4) Adopt reasonable locational installed capacity requirements with locally varying demand curves;
5) Consider protecting against capacity exports during times of tight supply through the use of capacity prices that fluctuate seasonally;
6) Investigate the dependability of capacity import contracts during times of high West-wide load;
7) Make the fixed-cost recovery curve explicit; and
8) Strive for regulatory credibility.

<u>CAISO Response to Staff Recommendations</u>

Recommendation 1 - Adopt a short-run capacity market approach with a downward sloping capacity-demand curve for the CAISO

The CAISO urges the Commission to move cautiously when considering adoption of a short-term capacity market with an explicit demand curve. While the CAISO agrees with staff that there are many attractive and useful features to a short-term capacity market such as that implemented in New York and proposed in New England, the Commission should fully consider the ramifications of doing so, including the potential cost impact on consumers and, more importantly, the risk/reward benefit of doing so. The administrative demand curves used in the New York market are a useful means to price "reliability" in the larger marketplace, but, as noted above by the CAISO, there are potential inefficiencies, i.e., higher costs, that result from such approaches.

Perhaps most importantly, and as further highlighted in response to Recommendation No. 8, consideration of a short-term capacity market should be part of a larger effort to define and lay out a longer-term "roadmap" for California. A short-term capacity market may be a useful feature to implement in the near-term – in part to stabilize the market and begin to establish transparent market prices for capacity (and reliability) – with a goal of evolving the larger market design to something more robust – perhaps a workable energy-only design or some other form of resource adequacy program – some time in the future.

Recommendation 2 - Further investigate alternative availability metrics (e.g., UCAP v. ISO-NE's proposed metric based on performance during shortage conditions) and ensure development of an availability metric that is applicable to hydro, wind, thermal and other generation technologies, and to appropriate demand response products

The CAISO agrees with Commission staff that vigorous availability metrics must be developed should the Commission recommend adoption of a short-term capacity market. While an energy-only design may be more efficient in creating the necessary incentives for resources to make themselves available during critical periods, it appears that some form of availability measures or metrics are needed under the somewhat muted price signals inherent in a capacity market. As opposed to a "UCAP v. Shortage Metric" issue, the CAISO believes that it is more important to view these measures as complementary and that perhaps a number of features will be necessary to fully address resource availability and the need to ensure that resources are available where and when needed.

As part of that consideration, the CAISO also urges the Commission to actively consider whether it may be appropriate to implement an operating reserve scarcity pricing mechanism as a complement to any capacity market design. While fundamentally a CAISO issue (since it will be CAISO that would implement such a feature), these issues are inexorably linked and should be considered together.

Finally, the staff recommends development of a metric that will "…ensure development of an availability metric that is applicable to hydro, wind, thermal and other generation technologies, and to appropriate demand response products." The CAISO strongly agrees on the need to define and establish availability metrics for different types of resources. If the Commission uses a reserve shortage metric for availability, the capacity product is now something that is available during reserve shortage hours, and "available" means providing energy or operating reserves in real time. Applying these definitions to different types of capacity, wind might have an average availability of 20-30% under UCAP, but its availability during reserve shortage hours (typically the hottest peak hours) may be near zero. So the value for capacity different types of plants will get depends on how you define the product and its availability. Ensuring the availability of resources during critical periods is a principal objective of the CAISO.

Recommendation 3 - Consider subtraction of peak energy rents from the capacity payment

The CAISO supports Commission staff's recommendation that peak energy rents should be subtracted from capacity payments if an explicit capacity market is used to ensure fixed cost recovery at a level consistent with meeting an investment (reserve) target. Although how this is done is a detailed design issue, the CAISO also generally supports using a "benchmark unit" to determine the level of energy market revenues to be credited during any given period.

The CAISO recommends that all revenue sources be considered when determining the appropriate payments under a capacity market structure. In addition to energy market revenues, the CAISO also recommends that ancillary service revenues also be accounted for and subtracted when determining capacity payments. This is an important consideration, especially if a reserve shortage pricing mechanism is implemented. Under such a mechanism, both energy and reserve prices, and therefore revenues, could be high during reserve shortage periods. Such revenues must be accounted for when determining the appropriate level of capacity payments under a capacity market structure.

Recommendation 4 - Adopt reasonable locational installed capacity requirements with locally varying demand curves

If a capacity market structure is proposed, the CAISO fully supports the development of locational capacity requirements. The CAISO believes that such requirements are critical to ensuring that appropriate price signals are provided at different locations to reflect the limits on delivering capacity between regions and the resulting locational differences in the value of capacity. Recognizing these locational differences will help ensure deliverability of resources to serve load on the system and to maintain local reliability. The development of locational capacity requirements has been and remains a fundamental piece of the reform proposal developed in other capacity markets and is a necessary feature of any capacity market.

The CAISO also recommends that the Commission explicitly consider and detail how such requirements can and will work in conjunction with both the CAISO's transmission planning process as well as the state's larger integrated planning process. While the CAISO believes that such mechanisms and processes are compatible with one another, they must be highly coordinated and work toward a common purpose – that of minimizing the overall cost of meeting loads at the levels of reliability for which they are willing to pay.

Finally, as discussed above under "Related Policy Issues", the CAISO recommends that the Commission consider the need to develop Capacity Transfer Rights, or their equivalent, as a companion to any locational capacity proposal.

Recommendation 5 - Consider protecting against capacity exports during times of tight supply through the use of capacity prices that fluctuate seasonally

The Commission staff recommends that capacity prices be allowed – or designed – to fluctuate seasonally so as to reflect the greater value of capacity during peak or critical seasons. The staff's goal is laudable to ensure that California can compete for and retain the resources necessary to serve load during capacity constrained periods of the year. While a design detail that could be developed – and has been proposed in the PJM market ("ICAP Reform Proposals" at 58-59) – the CAISO questions whether the staff's objective can be satisfied through other means, such as an operating reserve scarcity pricing mechanism to complement the capacity market framework. Such an approach has been adopted and implemented in the New York market and examination of its effectiveness there in attracting and/or retaining power during peak periods is warranted.

Recommendation 6 - Investigate the dependability of capacity import contracts during times of high West-wide load

The staff recommends investigating the dependability of capacity import contracts during times of high West-wide load. The CAISO believes that this issue is related to Recommendation 5 and the ability of California to attract and retain capacity during critical periods. While the CAISO agrees with staff that ensuring the dependability of imports is critical to California, the CAISO believes that such issues can readily be addressed by counting or resource qualifying criteria and, as identified by staff, ensuring that import contracts have penalty provisions that provide incentives for suppliers to ensure that such resources are made available to California when needed. At present, the CAISO does not see the need, or advise, to distinguish between internal and external capacity for purposes of setting prices in a capacity market. In fact, in order to ensure a deep and liquid market across the West (by developing uniform products) and to avoid any unintended incentives to export and then re-import power, the CAISO recommends that any type of bifurcated or non-uniform pricing be avoided.

Recommendation 7- Make the fixed-cost recovery curve explicit

The CAISO agrees with staff that should a demand-curve based capacity market be implemented in California, that such demand curve or fixed cost recovery curve be explicitly identified and transparent.

Recommendation 8 - Strive for regulatory credibility

The staff recommends that California begin with well-established designs (for capacity markets) and make modifications cautiously. In addition, the staff recommends that any design be well protected from the exercise of market power. Staff concludes that such an approach will ameliorate concerns regarding both price instability and regulatory credibility in the market. The CAISO generally concurs that such an approach is prudent.

Regulatory credibility and certainty will be critical if California is to attract and retain the resources necessary to reliably and efficiently serve load. Financiers and developers alike have stated that long-term financial commitments are a – if not the – fundamental prerequisite to securing investment in California's energy infrastructure. There are two ways to provide such certainty: (1) load-serving entities or the CAISO could enter into long-term (5-10 year) contracts to support new investment; or (2) regulators and policymakers can create a viable and stable regulatory environment that will allow investors to use and rely on the signals and potential revenue opportunities from short-term markets.

Option (1) is not attractive to load-serving entities or regulators because of the risk exposure and uncertainties surrounding load forecasts, customer base, and other issues. Option (1) is equally unattractive to the CAISO for the same reasons and the added complexity and perceptions of putting the CAISO in the middle of "market" transactions. Option (2) could work under either (a) an "energy-only" approach, where regulators and policymakers establish a "value" to reliability (Value of Lost Load or "VOLL") that enables suppliers to recover the full cost of their investments and resist the temptation to impose price or bid caps, or (b) under a short-term capacity market construct, similar to those in place and proposed in the eastern markets, where investors and developers have or gain a certain level of confidence in the robustness and stability of both the market design and the supporting regulatory framework.

Creating such a regulatory and market environment in California will be a challenge, but one towards which the staff of the CPUC has already made great strides by identifying and owning the important policy issues identified in the White Paper.

3. Roles and Responsibilities

The staff White Paper encourages comment on the respective roles and responsibilities to be allocated to the Commission and the CAISO with respect to conceptualizing, designing, and implementing any future capacity market construct. The CAISO concurs with staff that an appropriate allocation of responsibilities should seek to leverage the expertise of the respective entities, maximize cost efficiency and the use of existing resources, and respect jurisdictional boundaries. However, a delineation of particular responsibilities, such as which entity is in a better position to "draw the demand curve," would appear premature to the CAISO at this time. As emphasized above, the CAISO believes the Commission should deliberately and thoroughly evaluate various alternatives to achieving resource adequacy before recommending or endorsing any particular mechanism. The CAISO is fully committed to cooperating and facilitating the Commission's evaluation of the various options.

Notwithstanding the foregoing, a fundamental differentiation of responsibilities can be articulated. The staff's White Paper correctly identifies that the Commission should set "the reliability target" that the resource adequacy program is intended to satisfy. The reliability target defines how much reliability consumers should be willing to pay. This task appropriately falls within the province of a State decision-making body. Once the reliability target is selected and a choice is made regarding the mechanism to achieve that target, the CAISO remains willing to assume whatever design and implementation role assigned to it based on the considerations stated-above. Indeed, as discussed at length during the Commission's Phase 2 resource adequacy workshops, if the resource adequacy framework imposes standard obligations on suppliers or includes an explicit capacity auction mechanism with a "demand" curve as in the eastern ISOs, the CAISO understands that it may be in the best position to enforce compliance with such obligations and/or implement the auction approach. Accordingly, a discussion of appropriate roles should be part of the Commission's efforts to refine its assessment of various resource adequacy options.

4. Other Significant Issues

The White Paper and the CAISO's comments contained herein identify the significant issues before the Commission. The staff's White Paper correctly identifies a number of the important "lessons learned" from the eastern capacity markets and capacity market proposals and also identified a number of important related policy issues. In addition, the CAISO identifies other design issues that will require resolution during the detailed design stage, including the length or commitment horizon of any such capacity market, additional availability issues, transmission rights, and other matters.

Perhaps the most important "other" issue that must be addressed by the Commission is a clear outline of the regulatory process to come and how development of a long-term resource adequacy program can or need be staged. It is clear that neither Californians nor the market can wait an extended period of time for the CPUC and others to clarify these issues. While the regulatory process necessary to support thorough and timely recommendations on the issues raised in the White Paper may take several months, the Commission should immediately clarify that the regulatory resource adequacy framework developed over the last several years is still viable and will be in place beginning next year.

Specifically, the Commission should clarify that, until otherwise directed, each CPUC-jurisdictional load-serving entity will continue to have an obligation, beginning June 1, 2006, to: 1) procure the resources necessary to serve its load plus a 15-17% reserve margin; 2) demonstrate that it has procured 90% of those resources one year in advance and 100% of those resources one month in advance; 3) make sure the resources it has procured are deliverable; and 4) make all resource available to the CAISO to serve load on the system. Moreover, the Commission should move expeditiously to approve the final details of the resource adequacy and procurement rules, especially those related to the establishment of workable reporting, compliance, must-offer, and local capacity requirements.

III. CONCLUSION

The CAISO commends the Commission and its staff for identifying and taking ownership of the fundamental policy issues that must be addressed to secure needed investment in California's critical energy infrastructure. No progress can or will be made absent an acknowledgement of the market structure and institutional barriers that must be addressed and/or removed to facilitate informed investment in the energy system. The Commission staff has correctly identified the relevant issues. Now is the time for the Commission to step forward and address the fundamental policy issues that must be answered, regardless of what long-term resource adequacy program is ultimately adopted. Namely, the Commission need answer *How much reliability are consumers willing to pay for?*

Once that fundamental question is answered, the CAISO is prepared to develop the details of whatever resource adequacy structure is best suited to address California's needs. As always, the CAISO looks forward to collaboratively working with the Commission and its staff to further resolve these most important issues.

The CAISO thanks the Commission and its staff for issuing, and soliciting comments on, the White Paper.

September 23, 2005

Respectfully Submitted:

By:__________________________
Grant A. Rosenblum

Attorney for California Independent
System Operator Corporation

ATTACHMENT 1

ICAP SYSTEMS IN THE NORTHEAST:

TRENDS AND LESSONS

Scott M. Harvey

Prepared for Use of
California ISO

September 19, 2005

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ICAP SYSTEMS IN THE NORTHEAST: TRENDS AND LESSONS

Scott M. Harvey
August 19, 2005

I. OVERVIEW

The restructured PJM, New York and ISO-New England electricity markets all include installed capacity (ICAP) as well as energy markets. These ICAP markets are the successor to the reserve requirements of the power pools that preceded the ISO operated markets. Over time, these ICAP markets have encountered a variety of problems. Some of these problems have been more or less successfully addressed but others have grown more and more intractable, leading to proposals to substantially change the ICAP systems in PJM and New England.

This paper begins in Section II with a discussion of the origins of the current PJM, NYISO and ISO-New England ICAP systems and the problems they were intended to address. Section III turns to a description of the key features of these ICAP systems, organized around six problem areas, deliverability requirements, outage performance, unit availability, retail access, reserve margin determination and market power. Section IV provides a brief summary of the outcome of the RAM process which preceded the decision of PJM and ISO-NE to abandon their current ICAP systems and develop new approaches.[1]

II. WHY ICAP?

A. Origins of ICAP

Under the traditional vertically integrated utility model, resource adequacy standards were resolved between the individual utility and its regulators. The consequences of inadequate utility resources to meet utility load were straightforward, the utility that lacked sufficient generation to meet its load needed to buy energy and schedule transmission to import additional power or it would have to undertake involuntary load

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1 This paper is based upon a paper prepared in the Spring of 2004. The data in that paper has been updated to 2005 but the paper has not been updated to discuss proposals for changes in the PJM and ISO-NE ICAP markets that were developed after spring 2004. Portions of that earlier paper also provided the basis for the discussion of Resource Adequacy in Chapter X and Appendix V of Scott M. Harvey, William W. Hogan, and Susan L. Pope, "Comments on the California ISO MRTU LMP Market Design." The paper has benefited from the comments of Jim Bushnell, John Chandley, Steven Greenleaf and William Hogan. The views expressed here are those of the author and not necessarily those of any of the ISOs discussed. Any errors are solely the responsibility of the author.

shedding. The determination of which LSE would shed load during shortage conditions was easy; this was the utility that was short of power or did not have firm transmission service to deliver power to its load. The need for resource adequacy mechanisms, such as installed reserve requirements, the precursor of ICAP systems, initially arose in the Northeast from the implementation of economic dispatch which eliminated the link between an entity's generation and load. Individual utilities bought and sold power through the pool and their generating units followed pool dispatch instructions. An individual utility might be a net buyer during a shortage not because it was short of capacity, but merely because that utility's generation was the lowest cost source of operating reserves or regulation. This operating environment led to rules providing for shared responsibility for load shedding within the impacted region of the pools, rather than attempting to assign responsibility to the generation-short distribution company.[2]

Maintaining the capacity needed to meet peak load on a one-day-in-ten-year reliability criteria is very expensive on a per MWh basis, however. Moreover, because marginal capacity will almost never be used, maintaining this capacity can materially raise the overall cost of meeting load. Shared responsibility for load shedding therefore gave rise to the prospect that individual utilities would choose to reduce their costs by not incurring the high cost of maintaining the capacity needed to meet their peak load at conventional reliability levels, knowing that most of any resulting load shedding would be borne by the customers of other utilities. Installed reserve requirements, the pre-cursor of ICAP markets, therefore arose in part to ensure that all pool members incurred the cost of maintaining the capacity needed to meet peak day load on a reliable basis.

A similar logic may have operated in the Midwest under some of the reserve sharing agreements. If the members of a reserve sharing group are to agree to shared activation of reserves, there is a parallel need to make sure that all of the entities benefiting from the reserve sharing agreement incur the cost of maintaining enough capacity to provide reserves to the other members of the reserve sharing group under stressed system conditions. The MAPP region in particular appears to have developed rules designed to avoid free riding under the reserve sharing agreement and ensuring that all participants bore the costs of maintaining capacity adequacy.

Importantly, these reliability structures could not historically rely on prices to allocate energy within the pool or reserve sharing group during shortages as energy was bought and sold at cost based rates that did not reflect the value of energy or capacity during these shortage conditions.

One alternative for maintaining reliability within ISO coordinated markets of the Northeast pools when the pools transitioned to ISO dispatched open access markets was

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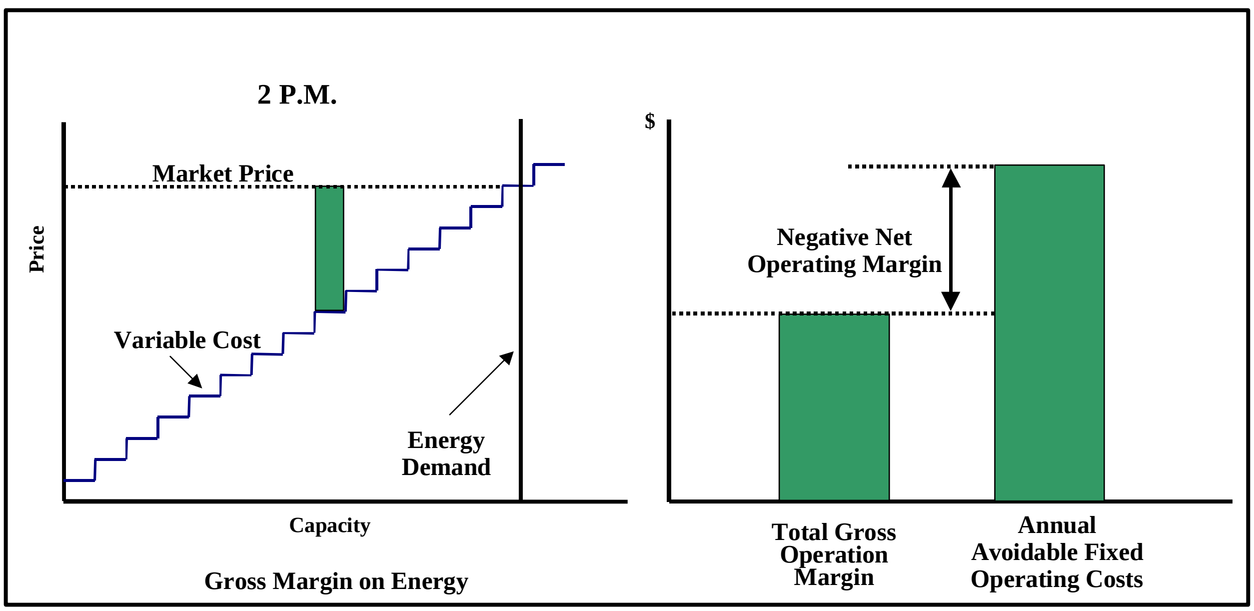
[2] Of course, to the extent that only a single distribution company served load within the constrained region in which there were inadequate resources available to meet firm load, the load shedding would fall entirely on the responsible distribution company. This will not necessarily be the case, however.

therefore to maintain the reserve requirements of the power pools in some form as a reliability mechanism. The need for such a reliability mechanism was increased by the $1,000/MWh bid cap, the imperfect shortage pricing that existed at start up of the PJM and NYISO, and the intent of several states to utilize transmission open access to support retail access programs.

B. ICAP Market Systems

Price equal to the short-run marginal cost of the marginal supplier is a basic short-run equilibrium condition. With the introduction of market-based marginal cost pricing in energy markets, infra-marginal generation earned revenues on sales of energy and ancillary services, earning margins equal to the difference between its revenues and the variable costs incurred in generating energy, as portrayed in Figure 1. Generation also incurs fixed costs, some of which can be avoided if the generation owner chooses not to make its capacity available for operation (i.e., if the capacity is either mothballed or closed permanently). In the absence of an ICAP or installed reserve requirement, generation owners will not choose to keep capacity in operation for dispatch unless their gross operating margin exceeds their avoidable fixed operating costs.

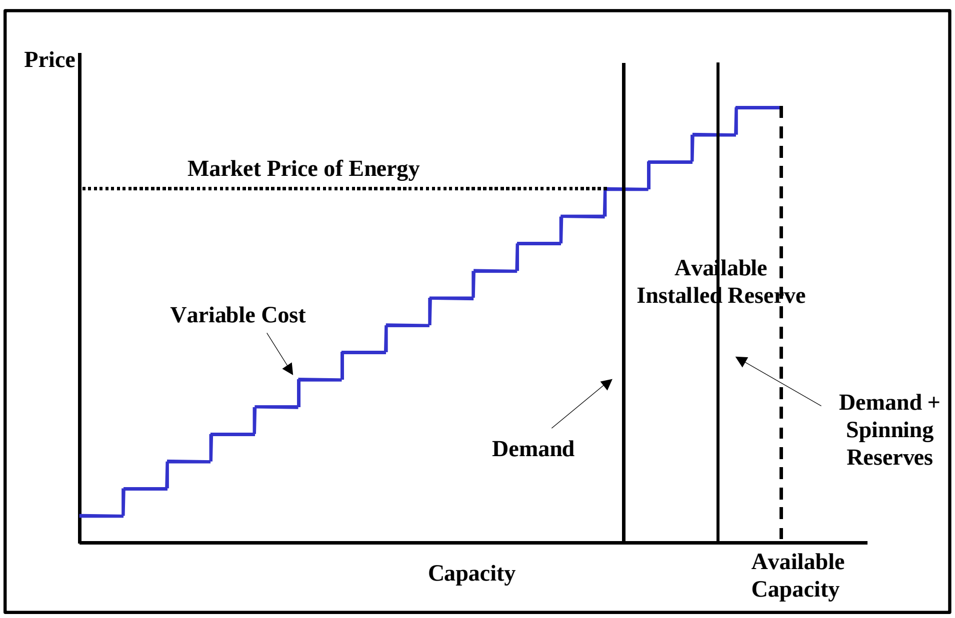
Figure 1
Generator Operating Margins



Under an ICAP system, the capacity requirement is established such that there is almost always sufficient capacity to avoid involuntary load shedding.[3] The wholesale energy market therefore usually clears at the intersection of demand and the variable cost (dispatch) curve, as portrayed in Figure 2. Because the price of energy is generally set by the incremental cost of the energy generated by marginal units, the price is not high enough often enough to cover the full cost of keeping these marginal units in operation over the year (i.e., the units will have a negative net operating margin as portrayed in Figure 1), unless the energy price is extremely high during hours of reserve shortage.

Under an ICAP system, the negative net operating margin is recovered by imposing a market-wide ICAP requirement symmetrically on all load-serving entities within the market. LSEs may not have the traditional obligation to serve, but under an ICAP system they must demonstrate reserves sufficient to meet the installed capacity requirement for their customers. If the amount of generation required to be available under the installed capacity requirement exceeds the amount of generation that would have been available in the absence of such a requirement (i.e., the amount justified by energy and reserve market revenues alone), a market for capacity is created. Thus, with such a binding ICAP requirement, capacity takes on value in and of itself. Marginal units, unprofitable on the margins they earn on energy sales and ancillary services, would demand a capacity payment in return for agreeing to make themselves available for operation and allowing the contracting LSE to satisfy its ICAP requirement.

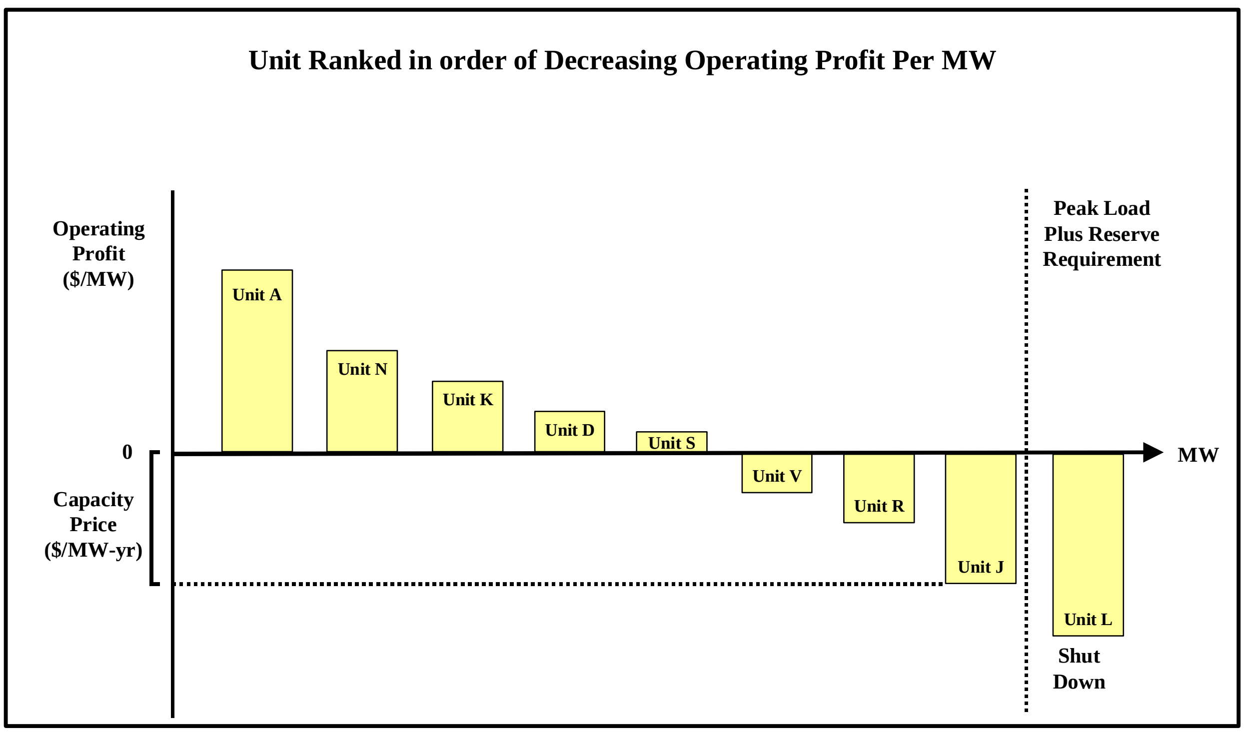
Figure 2
Energy Market Prices with Installed Capacity Requirements



3 The number of hours of reserve shortage (i.e., emergency state operation) is relatively low but the frequency of reserve shortage exceeds the one-day-in-ten-year load shedding standard. Only severe reserve shortages result in load shedding.

To keep capacity open under an ICAP system, the owner of the marginal unit requires a capacity payment of at least the difference between its avoidable fixed operating costs and its net margin on energy and ancillary services sales (i.e., it must recover the negative net operating margin portrayed in Figure 1 on an expected value basis). Competition among capacity owners and with potential entrants should cause the market-clearing capacity payment to approximate the per-MW payment that would induce just enough generation to remain available to enable the ICAP requirement to be met. Under a market-based ICAP system, all generating capacity contracting to provide installed reserves are paid the market-clearing price of capacity, as portrayed in Figure 3. Between the capacity payments they receive and their margins on energy sales and ancillary services, all units providing the capacity needed to meet the ICAP requirements would earn enough to cover their avoidable fixed operating costs and thus would remain available.

Figure 3
Determination of Market Price of Capacity



With an ICAP requirement, the capacity payment is determined by the per-MW payment required to enable the marginal unit (Unit J in Figure 3) to at least break even and capped by the payment required to keep the next most expensive unit in operation (Unit L). For existing capacity, the breakeven point would be based on going-forward costs while for a new entrant the breakeven point would include a return of and on investment. Because the market can meet the ICAP reserve requirement without Unit L, the market-clearing capacity payment would be insufficient for it to cover its anticipated operating losses and Unit L would close. Between the capacity payments they receive and their margins on energy and ancillary services sales, each of the other units remaining open would make at least enough to cover their avoidable fixed operating costs. Because ICAP suppliers would be paid the market-clearing price, most incumbent ICAP suppliers would earn more than their going-forward costs. This is inherent in a market-based system. Conversely, however, incumbent suppliers would not be assured of returning a return of and on their investment, but only their going-forward costs.

Installed capacity systems have several potential limitations:

- An ICAP system ensures that the electricity market clears by keeping generating capacity that cannot recover its costs in the energy and ancillary services market in operation. The cost of keeping this capacity available may exceed its actual value to consumers.
- A set of rules is required to govern the location of qualifying capacity.
- A set of rules is required to govern generator operational availability.
- A set of rules is required to govern the treatment of imports.
- There is a potential for free-riding by any loads not required to maintain installed reserves.
- Low energy prices mean that there will be too little incentive for loads to become price-responsive in real time unless this incentive is built into the ICAP system.
- Absent additional rules, an ICAP system ensures the availability of capacity but does not ensure that energy is available in any particular quantity at any particular price from this capacity.
- There is a potential for a short-term ICAP system to become little more than a second payment for energy.
- There is a potential for the exercise of market power that can be difficult to address without undermining other policy goals (reliability, retail access).

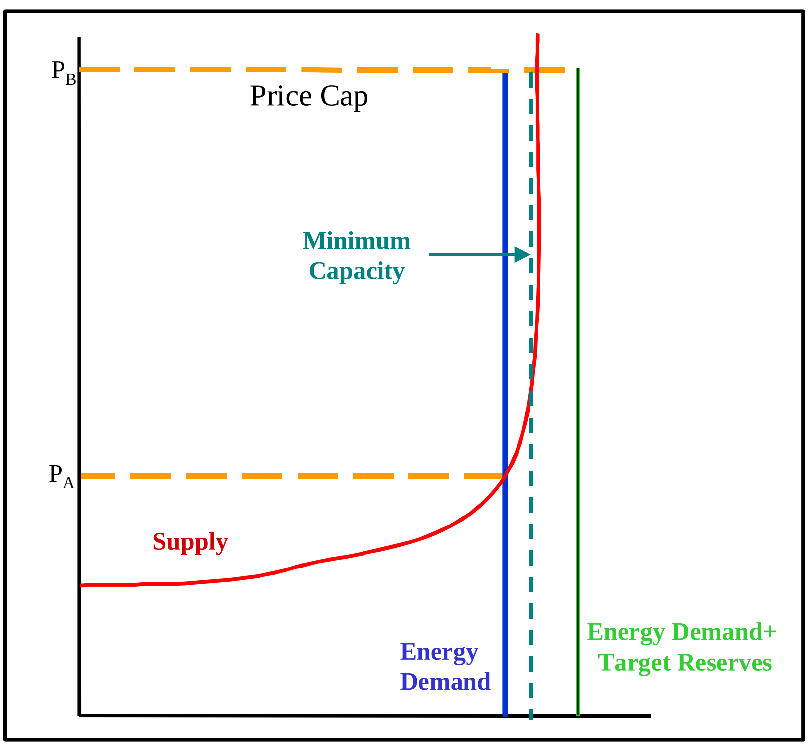
These issues are discussed in Section III. Before turning to a discussion of these issues, it will be helpful to first discuss the alternative of relying solely on energy and reserve pricing to maintain resource adequacy and reliability.

C. Energy-Only Pricing

An alternative to an ICAP system in maintaining resource adequacy is to structure energy and ancillary service markets such that the marginal generator is able to recover its going-forward costs in energy and ancillary service prices. In principle, the changes needed to implement such an energy market-based resource adequacy system are to implement shortage pricing that causes the prices of energy and ancillary services to rise to a sufficiently high level during shortage conditions that the marginal capacity supplier required to meet established reliability criteria is able to recover its going-forward costs during these shortage hours.

For vertically integrated utilities such an energy only market could operate much like an ICAP system. The pool operator/ISO could determine the shortage prices that it estimates are required to keep sufficient capacity available to meet the target level of reliability and could inform the vertically integrated utilities of the implied reserve margin. The shortage pricing would support the implied reserve margin as the pricing system would imply that there would be enough hours with high prices to justify keeping the target level of capacity in operation. Nevertheless, there are some reliability risks in this market design and these risks are magnified in markets with unintegrated retailers and suppliers.

Figure 4
Supply and Demand in a Shortage



A fundamental feature of an energy-only market design is that with vertical demand and competitive markets, the market price of energy and reserves only exceeds the incremental costs of the marginal generator when the control area is reserve short. As long as these reserve shortages are small, they will have little impact on reliability, so conventional reliability standards can be consistent with an energy shortage pricing system. Thus, as portrayed in Figure 4, the price would rise to the price cap when reserves fell below the target level, but involuntary load shedding would occur only when capacity fell below a lower threshold, labeled the minimum capacity level in Figure 4. A practical difficulty in implementing such a market design is that actual peak load is uncertain, as is the available capacity (due to random outages). In consequence, the more often the system is expected to be in a reserve short condition, the greater the potential for bad luck in terms of weather or outages to throw the system into the range in which involuntary load shedding is required.

If the short-term demand for electric energy is completely price-inelastic, then the capacity needed to maintain a given level of reliability is the same under an energy-only pricing system or under a conventional reserve margin system. The potential complexity under an energy-only pricing system is that the shortage pricing system must be implemented in such a manner that the capacity needed to maintain the desired reliability level earns its going-forward costs during the number of hours of reserve shortage that are consistent with the desired reliability level.

From this perspective, there are three basic reliability risks in relying on an energy-only pricing system to meet price-inelastic demand:

- Miscalculation of the cost of capacity by the pool/ISO, resulting in too little capacity in operation to maintain intended reliability levels.
- Miscalculation of expected prices by LSEs/suppliers, resulting in too little capacity in operation to maintain intended reliability levels.
- The shortage frequency required to sustain the marginal unit is inconsistent with intended reliability levels.

Each of these risks is discussed below.

Miscalculation of Capacity Costs

Under an ICAP system the pool operator determines the reserve margin and ICAP requirement through Monte Carlo type analysis of reliability under stressed system conditions. Importantly, the calculated reserve margin does not depend on the cost of having capacity available during stressed system conditions. Instead, the pool operator determines the physical capacity requirements and the cost of keeping this capacity in operation is, in principle, determined in the market by the supply decisions of resource providers.

Under an energy pricing system driven by shortage pricing, however, the amount of capacity that will be made available by resource suppliers in response to any set of shortage prices depends on the cost of having this capacity available during those shortage conditions. If the pool operator misunderstands the cost of having capacity available or miscalculates the revenues generated by marginal capacity during non-stressed conditions, then a given set of shortage prices may result in more or less capacity being available than expected by the pool operator, resulting in a different level of reliability than planned for by the pool operator and regulators. Since the pool operator does not participate in commercial markets there is a potential under energy-only pricing with price-inelastic demand for the pool operator to significantly misassess the cost of having generating capacity available during peak conditions, resulting in more or less capacity being available than assumed in the pool operator's reliability analyses.

If there is a strong link between the shortage costs used by the pool operator and the actual reliability value of capacity during those conditions, this kind of error might not be important in terms of its impact on consumer welfare as the shortage prices would reflect the value of the capacity. Absent such a strong link, there is a potential for misestimation of capacity costs by the pool operator to lead to a material difference between the actual and intended level of reliability.

Miscalculation of Expected Prices

While suppliers have a good sense of the overall cost of keeping their capacity available, both suppliers and LSEs may have considerable difficulty projecting expected annual net revenues based on the pool operators shortage cost rules. The expected price level would depend on both generation and transmission outage probabilities as well as the supply of imports. If suppliers and LSEs have different expectations than the pool operator about the frequency and degree of shortage conditions, then they will not provide the anticipated level of capacity in response to a given set of shortage prices, even if the pool operator accurately assesses the cost of providing this capacity. While the system operator could make public its profile of simulated shortage prices, it is not clear that market participants would necessarily find it commercially reasonable to rely on these results.

A further potential source of divergent expectations under energy-only pricing is the assessment by resource suppliers of the likelihood that regulators will permit high market prices, even during shortage conditions. Thus, if the nominal price cap were $10,000/MW, the pool operators' assessment might be that the marginal supplier would recover its entire net operating revenue shortfall of $50,000/MW during eight hours of shortage conditions in which the price of power was projected to exceed $5,000/MW. If the resource owner did not believe that it would be permitted to earn more than $1,000/MWh during these market conditions, the revenue assessment of the pool operator and market participant would be radically different and much less capacity might be forthcoming than assumed by the pool operator. In principle, market participants should over time be able to assess the accuracy of the pool operator price forecast, as well as the price level regulators would allow, but the reality is that the forecast by resource suppliers and the pool operator will be based on expected conditions. Even an accurate forecast may only average out to reflect actual prices over a period of a number of years, and conditions may be changing more rapidly than the actual outcomes converge on the forecast. It may therefore be difficult or impossible for market participants to distinguish whether price estimates are biased ex ante or are accurate estimates of volatile conditions and prices.

Required Shortage Frequency

Under an energy-only pricing system, there is a very explicit tradeoff between the expected price level during shortages and the number of shortage hours required to recover a given net operating cost shortfall. The greater the number of hours of reserve shortage, however, the greater the likelihood that the shortage in some hours will be sufficiently severe as to require involuntary load shedding. Thus, the lower the shortage price in the energy market, the larger the number of shortage hours required to recover a given operating cost shortfall, and the more likely that load shedding will be necessary during some of the shortage hours.

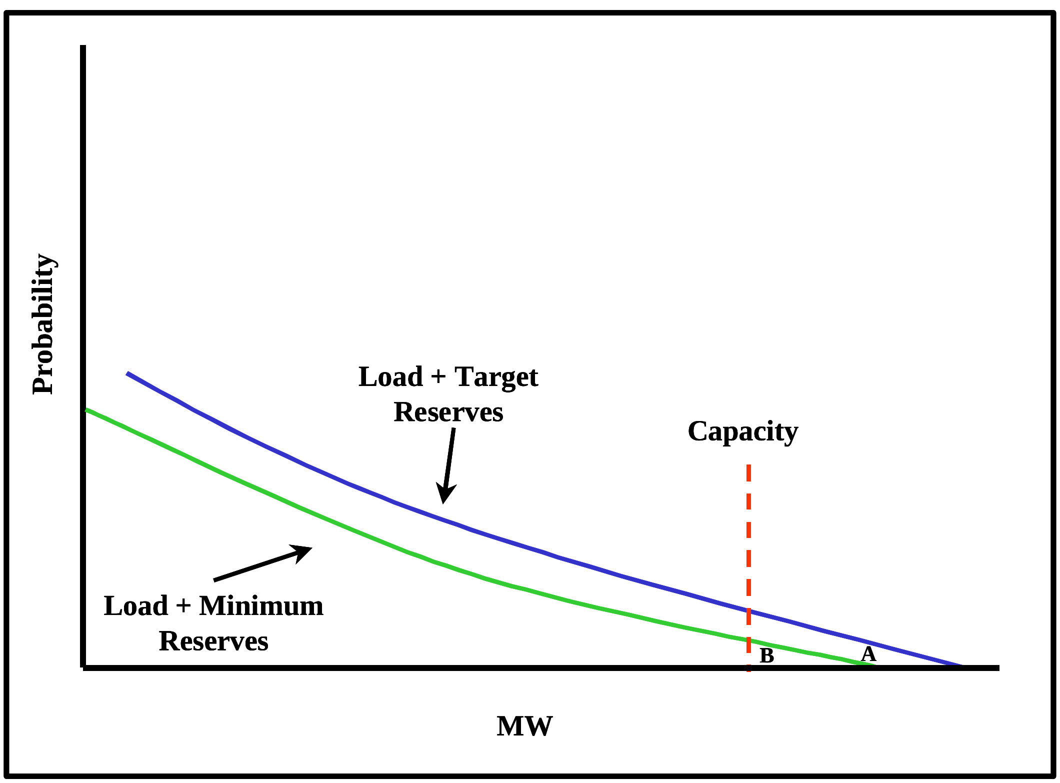
As suggested in the illustration above, with a price cap of $10,000/MWh and effective shortage pricing, a small number of shortage hours could be sufficient for the marginal generator with an incremental running costs of $100/MWh to recover $50,000/MW in going-forward costs. Given this small number of shortage hours, the probability distribution of demand and supply surprises might yield a one-day-in-ten years probability of such a large capacity shortage that load shedding was required.

Suppose, on the other hand , that the price cap were $1,000/MWh and there was no other form of shortage pricing. The most that the marginal generator could recover during a shortage hour would be $900/MWh. The number of shortage hours required for the marginal generator to recover its going forward costs on an expected basis would be around 55 hours per year. A capacity balance tight enough to produce 55 hours per year of shortage conditions, however, would likely have a much greater risk of requiring load shedding than if only 8 hours were expected, and the increase in likelihood might be non-linear.

At the extreme, suppose the price cap was set at $250/MW with no other shortage pricing as in California. In this circumstance around 333 hours of reserve shortage would need to be expected on an average annual basis for such a marginal generator to recover its going forward costs in energy prices alone. Such a high frequency of reserve shortages would in turn produce a very high probability of involuntary load shedding.

Figure 5 portrays this dilemma in terms of the probability distribution of load plus the target level of reserves, and load plus the minimum level of reserves. A shortage arises and prices rise above incremental cost when available capacity is less than load plus the target level of reserves. In Figure 5 the probability of this occurring is the region A + B. Since lower capacity levels imply larger areas A +B, capacity would exit until the probability of shortage is high enough given shortage pricing to make it profitable to keep the remaining capacity in operation. The difficult trade off under an energy only pricing system with inelastic demand is that the lower the level of capacity, the larger is area B, which is the probability of involuntary load shedding. If the difference between the minimum level of reserves and the target level of reserves is small relative to the slope of the probability function of loads, then high shortage pricing levels will be required for the profits earned during the shortage conditions that occur with probability A+B to support the level of capacity required for probability B to be appropriately small. Moreover, the smaller the difference between the minimum level of reserves and the target level of reserves relative to the slope of the probability fraction of loads, the greater the potential for mistaken evaluation of the probability A + B to result in a load shedding probability (B) that differs from the efficient level.

Figure 5



An energy-only pricing system is therefore likely workable from a reliability standpoint with price-inelastic demand only if prices are very high during shortage conditions. This requirement can be potentially problematic from two perspectives. First, if even small reserve shortages result in prices of $5,000/MWh or more, there would potentially be an incentive for energy suppliers to physically withhold capacity in order to produce reserve shortages and drive prices to the high levels associated with shortage conditions. Second, the variability of supply and demand conditions will make it likely that resource suppliers will not recover their going-forward costs evenly year to year, but rather the recovery will be concentrated in particular years.[4] This price pattern could sustain multi-year energy contracts that would recover generator going-forward costs. Under retail access systems, however, there may not be many multi-year energy contracts and thus most customers would be exposed to energy prices during the one year in five or six in which suppliers recover their going forward costs. This implies large variations in retail prices that may not be realizable within the regulatory structure.

The continued reliance on ICAP markets after several years' experience with deregulated generation markets appears to be motivated in large part by a perception that an ICAP system avoids the potential for the exercise of market power that can exist under energy-only pricing systems and that it avoids the substantial price volatility that will inevitably exist under energy-only pricing systems that permit energy and reserve prices to reach value-of-lost-load levels during shortage conditions. As discussed below, neither of these perceptions is necessarily valid.

Three elements of the evolving NYISO market design address these limitations of an energy-only market system. First, the explicit reserve markets of the NYISO provide an additional relatively stable income stream for the marginal ICAP resource, which should be a 10-minute combustion turbine located east of Central East. Nevertheless, the historical expected reserve market earnings of around $10,000/MWyear fall far short of what is required to keep the marginal unit in operation.

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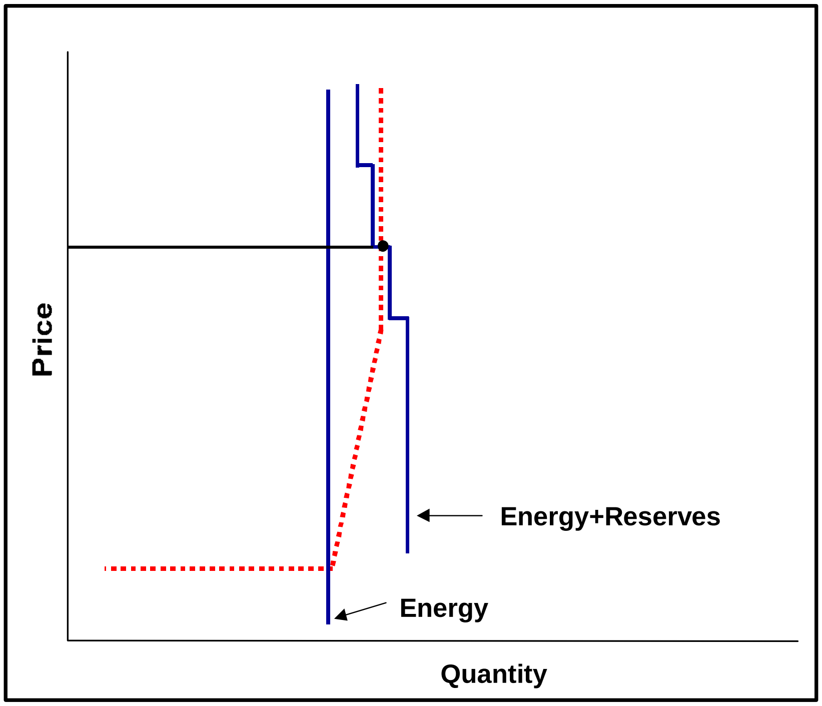
[4] Thus, a marginal generator with a going forward cost of $50,000/MW year might anticipate recovering $15,000/MW year in most years but recovering $200,000/MW year every five years or so.

Second, the reserve demand curve implemented for 30-minute reserves by the NYISO prior to the summer of 2002 addresses the potential for the exercise of market power by in effect making the residual demand curve facing a supplier with market power in the energy market more price elastic than would otherwise be the case as shown in Figure 6.[5] In addition, the demand curve somewhat raises energy prices during shortage conditions, even if suppliers bid their costs.

Figure 6
NYISO Reserve Demand Curve



Third, the reserve shortage pricing introduced for 10-minute and spinning reserves on February 1, 2005 allows real-time energy and reserve prices to reach several thousand dollars per MW, as a result of reserve shortages, even with the $1,000/MWh bid cap. While this shortage pricing system provides marginal incentives for generator performance during strained system conditions, the shortage values are currently set far too low to obviate the need for an ICAP system. Current reserve shortage values will produce margins approaching $2,000 only during conditions that are planned to occur for only a few hours a year and materially higher frequencies could entail involuntary load shedding.

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5 The reserve demand curve reduces the quantity of 30-minute reserves based on the shadow price of 30-minute reserves. If the shadow price of 30-minute reserves reaches $50/MW the amount scheduled can fall by up to 200 MW to 1,400 MW. If the shadow price of 30-minute reserves reaches $100/MW, the amount scheduled an fall by up to 400 MW to 1,200 MW. If the shadow price of 30-minute reserves reaches $200/MW, the amount scheduled can fall by up to 600 MW to 1,200 MW.

The potential for all of these kinds of miscalculation and the recognition that there would be little or no price sensitive load in the short run, as well as a reluctance to allow extremely high energy prices, lay behind part of the initial reluctance to rely on energy only pricing to maintain reliability for the initial implementation of LMP markets in New York and PJM.

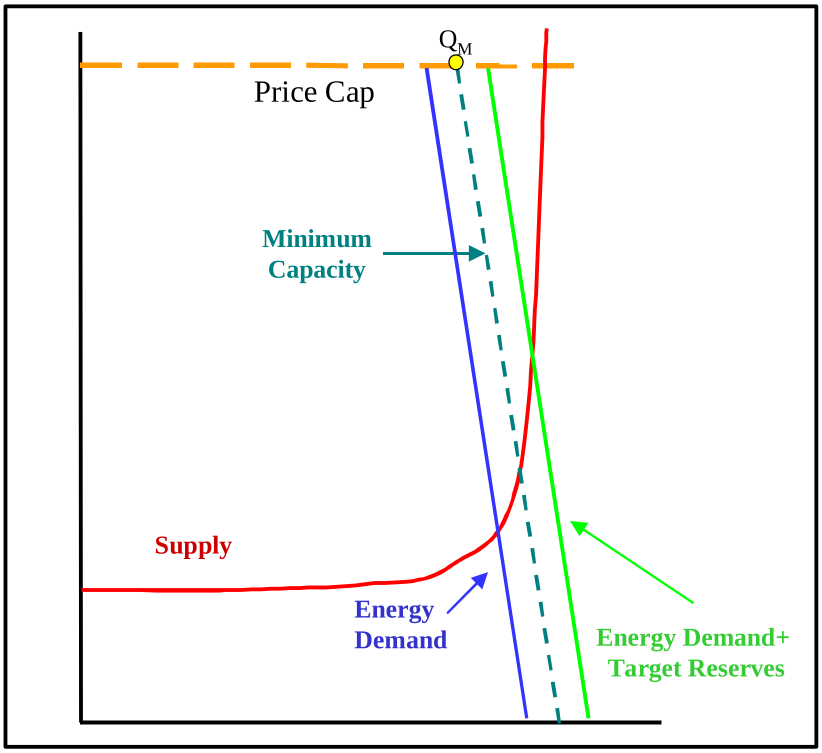
D. Energy-Only Pricing with Price-Responsive Real-Time Load

The potential reliability risks associated with energy only pricing in vertically unbundled generation markets discussed above are likely to be greatly reduced or even eliminated if the real-time demand for power is price responsive. In an energy-only pricing system with price-responsive real-time load, market clearance and reliability can be ensured by price-responsive real-time customer demand, without the need for administratively determined installed reserve requirements and without undue reliability risk.

- Operating reserve margins would be maintained by price-responsive load reducing consumption in response to high prices.
- There would be no administrative reserve requirement or capacity payment. Long-term capacity decisions would be left to market incentives.
- The electricity market would clear while providing reliability, through operating reserve standards, energy pricing and market-determined installed reserve levels.

In a market with a substantial amount of price sensitive load, errors in assessing the frequency of shortages would not be of great importance from a reliability standpoint as the errors would result in variations in market prices but firm load would be met. Similarly, if there is adequate price-responsive load, even frequent reserve shortages need not lead to involuntary load shedding. The crux of such a system is that rather than shocks such as unexpected weather or unusual levels of generation outages translating into reduced operating reserves and higher load shedding risk, these shocks would result in higher prices that would lead to voluntary load reductions that would maintain operating reserves. Thus, the demand curve portrayed in Figure 7 could shift out considerably, or outages considerably shift in the supply curve without the minimum level of energy demand plus minimum reserves (Qm) exceeding the available capacity.

Figure 7
Energy Pricing with Price-Responsive Load



If, however, there is little or no price sensitive load within the range that energy and reserve markets are permitted to clear, then errors either by the ISO in assessing the cost of capacity or by suppliers in assessing expected prices could translate under an energy-only pricing system into differences in the frequency of reserve shortage conditions and inefficiently high probabilities of involuntary load shedding.

Peak energy consumption would likely be lower under an energy-only market with price-responsive load than under an ICAP system because consumers could avoid paying for energy whose true cost of production exceeds its value by reducing consumption during high-priced peak periods.

Energy-only pricing systems based on price-responsive load have some potential limitations relative to an ICAP system. First, these pricing systems are assured of maintaining reliability and avoiding the risks associated with energy-only pricing for price-inelastic demand only if there is in fact sufficient load responding to short-term price signals to enable the market to clear during shortage conditions while maintaining reliability levels and while generating substantial price cost margins for the available generation resources. Thus, there have to be truly effective demand response programs that can be relied upon to produce real load reductions during high load conditions.

Second, practical experience suggests that only limited demand response is available at low energy prices. State and federal regulators must be willing to allow real-time energy prices to rise well above the incremental cost of the marginal generator during reserve shortage conditions in order for demand response to be effective in maintaining reliability. The presence of price-responsive load does not change the reality that the marginal generator must be able to recover its going-forward fixed operating costs. While the presence of substantial price-responsive load greatly reduces or eliminates the potential reliability risks arising from misjudgments regarding generation margins and capacity adequacy under an energy-only market, it does not solve the political problem that generator cost recovery entails high energy prices during a significant number of hours. Moreover, unless demand is very price-elastic or demand peaks very regular, there is a potential for substantial energy price volatility with the recovery of generator fixed costs concentrated in particular years. This price volatility may create insurmountable political and regulatory risks under retail access systems lacking multi-year energy contracts to hedge prices.

Thus, even with price-responsive load there will be concerns regarding the potential for the exercise of market power during shortage conditions and concerns regarding the level of price volatility. A third concern may be that customers lacking real-time meters will be unable to avoid paying for power that may, at times, be expensive even if they do not consume power during the periods when it is expensive.[6]

While ICAP markets may sometimes be viewed as avoiding these potential concerns regarding the operation of energy only markets, this is not necessarily the reality. As discussed below, relying on ICAP markets does not avoid market power problems (Section III.G), and under either an energy-only market, an ICAP system or a system in which load is met with the regulated generation of the vertically integrated utility, consumers in the end must pay the going-forward costs of existing generation as well as a return of and on investment for new generation. Moreover, an ICAP system can create a wide variety of performance issues on the generation side that may be better managed under an energy-only pricing system (Sections III B, C, D). These and other issues in actually implementing ICAP systems are discussed in Section III.

III. ICAP DESIGN ISSUES

Most of the turmoil in Eastern ICAP markets since 1998 has revolved around basically the same set of issues in each of these markets. The description of the Eastern ICAP

[6] It needs to be kept in mind, however, that consumers are also unable to avoid paying for very expensive power under ICAP systems or under traditional utility cost-of-service pricing.

markets is organized around these core issues, explaining how these common issues are addressed in each market.

A. Defining ICAP Requirements

1. Reserve Margin

The New York State Reliability Council determines on an annual basis the installed reserve margin required for the NYISO to satisfy NPCC Resource Adequacy criteria of a one day in ten years probability of shedding firm load due to inadequate resources. This is a probabilistic Monte Carlo analysis that takes account of scheduled and forced outages and deratings, availability of imports from neighboring control areas, and capacity or load relief available through operating procedures.[7]

The NYISO then determines the minimum installed capacity requirement for the NY control area as the product of the forecasted control area peak load and 1 plus the reserve margin. The NYISO translates the minimum installed capacity requirement (ICAP) into a minimum unforced capacity requirement (UCAP, discussed more fully in Section C) by multiplying the installed capacity requirement times 1- the average EFORd value of six most recent 12-month rolling average EFORds of all New York resources in the New York control areas.[8] The NYISO also determines the locational minimum installed capacity requirements for Long Island and New York City.[9]

PJM's process for determining its current installed capacity requirements is similar to New York's. Electric distribution companies submit their load forecasts for the planning period to the PJM. PJM uses distribution company forecasts as well as historic peak load information to determine zonal peak load forecasts for the planning period.

PJM and PJM's Reliability Assurance Agreement Reliability Committee determines the PJM reserve margin. This reserve margin is determined through a probabilistic analysis that accounts for both load forecast uncertainty, maintenance outage requirements and uncertain generator forced outages based on historic EFORd rates. The current expected loss of load probability target is one day in ten years.[10] The

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7 NYISO Installed Capacity Manual, p. 2-3; New York State Reliability Council LLC, Policy No. 5-0, Procedure for Establishing New York Control Area Installed Capacity Requirements, August 11, 2003; New York State Reliability Council, LLC, Installed Capacity Subcommittee, New York Control Area Installed Capacity Requirements For the Period May 2005 through April 2006, December 10, 2004, Appendix A (hereafter NYSRC 2004).

8 NYISO Installed Capacity Manual, p. 2-3.

9 NYISO Installed Capacity Manual, p. 2-3.

10 PJM Manual 20, pp. 17-22. PJM Reliability Assurance Agreement, May 17, 2004, Schedules 4, 4.1.

historic EFORd ratio is then used to convert the ICAP requirement into a UCAP requirement.

ISO-NE uses a similar one day in ten year loss of load criteria based on similar analysis of scheduled and forced outages, assistance from external control areas and capacity or load relief from operating procedures to determine the NEPOOL reserve margin.[11] As in PJM and NYISO, a historic EFORd ratio is then used to convert the ICAP requirement into a UCAP requirement.

2. Allocating ICAP Requirements

Once the aggregate UCAP requirement for each control area for the forthcoming year has been determined, it is allocated to LSEs.[12] Under the original ICAP systems implemented by Northeast ISOs, LSEs purchased UCAP to meet their assigned requirement or paid a deficiency charge for their shortfall. This deficiency payment was loosely related to the cost of a gas turbine. The current PJM deficiency charge is $160/MW day, $58,400 MW year, divided by one minus the average EFORd.[13]

New England

New England's procedures for allocating UCAP responsibility to LSEs are the simplest. UCAP requirements are allocated to each load in proportion to that load's share of the current year's system peak load. System peak load is measured as load during the single highest load hour for the ISO-NE control area. Each LSE's UCAP requirement is then the sum of the UCAP requirements allocated to the loads it serves.[14]

PJM

PJM uses a slightly different procedure to measure system peak load and reflects anticipated load growth in its allocation mechanism. UCAP requirements are allocated among zones (i.e., areas served by a single utility), in proportion to each zone's forecasted share of the forthcoming year's system peak load. System peak load is measured as the average of loads during the five highest load hours for the PJM control

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11 ISO New England, Manual for Installed Capacity, p. 1-4 and 1-5.

12 To be precise, it is a UCAP requirement that is assigned to LSEs. The distinction between ICAP and UCAP is explained in Section C.

13 PJM Reliability Assurance Agreement, May 17, 2004, Schedule 11.

14 ISO-NE ICAP Manual, Section 2.1.

area. Each zone's share of UCAP requirements is then allocated to loads in that zone in proportion to each load's current-year contribution to system peak load.[15]

New York

New York also reflects anticipated load growth in its allocation, but it does not allocate requirements based on shares of system peak load. Instead UCAP requirements are allocated among transmission districts (TDs), which are similar to PJM's zones, in proportion to the forecast for each TD's individual peak load for the forthcoming year. The TD peak is measured as load during the single hour in which load in the TD is highest. Each TD's share of UCAP requirements is then allocated to loads in that TD, in proportion to each load's forecast contribution to that TD's peak load, based on its actual contribution to peak load in the prior year.[16]

3. Demand Response

ICAP systems need to have mechanisms to account for and provide incentives for demand response programs, since the ICAP systems depress energy prices reducing the incentive for demand to reduce consumption during peak load conditions.

PJM has taken a somewhat different approach to demand response than ISO-NE and the NYISO. PJM's peak load forecast takes account of active load management capability, so qualifying demand response in effect avoids ICAP/UCAP charges.[17] The degree of capacity credit provided to ALM programs is determined in the probabilistic reliability analysis and can vary between 0 and 1.[18] A distinguishing feature of this system is that it is up to the LSE serving the load to provide demand response in order to reduce ICAP charges.

In New York demand response resources can qualify as special case resources which count as UCAP, i.e., they are awarded UCAP capacity that can be sold to LSEs to satisfy the LSE's ICAP requirement[19] Like generators providing UCAP, Special Case resources must be capable of reducing load for a minimum four hour block. Analogous to the obligation of generators to bid in the day-ahead market, Special Case Resources are

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15 PJM Manual 20, Reserve Requirements, Section 2, April 30, 2004.

16 NYISO ICAP Manual, Sections 3.3 and 3.4. There are also detailed rules governing customer switching (Sections 3.2 to 3.10).

17 PJM Manual 20, p. 11-14. PJM Reliability Assurance Agreement, May 17, 2004, Schedule 5.2.

18 PJM Manual 20, p. 25-26.

19 NYISO ICAP Manual, Section 4.12.

notified day-ahead that they may be needed. [20] During the operating day they will have two hours notice to reduce load. At present Special Case Resources are also paid in the energy market for their demand reductions.[21]

Unlike PJM, in New York the entity providing demand response need not be the entity serving the end use customers load. This is an intentional feature motivated by a perception[22] that the distribution companies that are the LSEs serving most load are not interested in nor well suited to providing demand response and would fail to develop these opportunities.

ISO-NE's approach to demand response is similar to New York. Demand resources in the Real-Time Demand Response or Real-Time Profiled Demand Response programs can qualify as UCAP resources and sell UICAP.[23] ISO-NE demand response must be able to interrupt upon two hours notice, without regard to day-ahead notification.[24]

Both the NYISO and ISO-NE demand response programs have a variety of additional rules for measuring load and load reductions.

B. Deliverability

1. Overview

ICAP deliverability tests are a central issue in implementing ICAP systems in decentralized electricity markets, particularly with respect to the ability of new generators to participate in the ICAP market. PJM, NEPOOL and the NYISO rely on locational energy pricing for congestion management. This has enabled all three ISOs to adopt a "minimum interconnect" standard for generators selling energy into the market. A new generator satisfies the "minimum interconnect" standard if it is able to deliver its power to the transmission grid without adversely affecting reliability and its interconnection (at zero energy dispatch) does not reduce transfer capability.

LMP pricing in energy markets provides new generators with incentives to site themselves efficiently, without restricting competition. Congestion impacts are reflected

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[20] The NYISO is generally obligated not to use this day-ahead notification "indiscriminately" but "only when the Day-Ahead Market indicates serious shortages of supply for the next day." NYISO ICAP Manual, p. 4-31.

[21] NYISO ICAP Manual, Section 4.12.8.

[22] This perception may or may not be correct.

[23] ISO New England Load Response Program Manual, Section 7.

[24] ISO-New England has two categories of real-time load response, 30 minute response and 2 hour response. The 30 minute load response is paid a higher price for its energy reductions. See ISO New England Load Response Program Manual, Section 2.2.

in the locational energy prices and thus in the revenues of both incumbents and entrants. Generators that locate at places where they often cannot be dispatched because of transmission constraints will earn low energy margins under LMP pricing. The prospect of low margins due to congestion thus serves to incent new generation to locate where capacity is needed and energy prices are higher. Generators receive ICAP payments, however, whether they operate or not, so there is no locational price signal in the ICAP market absent some form of deliverability requirement.[25]

Absent any form of deliverability requirement there is a potential for ICAP capacity to be developed in locations at which it is cheap to construct, even if, because of transmission constraints, the capacity adds little to the amount of power that can be used to meet load under stressed system conditions. The more important the ICAP payment is as a source of generator revenue, the greater the potential incentive problem. Thus, if almost all of the net margin of the marginal generator is derived from the energy market, it is less important to impose deliverability requirements in the ICAP market as capacity that is not dispatchable to meet load under stressed system conditions will likely be uneconomic regardless of whether a deliverability test is applied for ICAP purposes. The larger the proportion of revenues of the marginal generator that are derived from the ICAP market, however, the greater the potential, absent an ICAP deliverability requirement, for construction of generation that is not cost effective in terms of its contribution to regional reliability.

All three Northeast ISO's have struggled with how to apply some form of deliverability test to sellers in the ICAP market and have taken different approaches to resolving this problem. Such a test should satisfy at least three objectives.

- No barriers to entry: The deliverability test should preserve the condition for efficient entry to be profitable if the entrant's full generating costs are less than the avoidable generating costs of the incumbent.

- Permit long-term ICAP contracts: The deliverability test should permit long-term bilateral contracts for ICAP. This requires that ICAP sellers be able to hedge themselves against the impact of future entry of new capacity on their deliverability.

- Reflect reliability criteria: The deliverability test needs to ensure that capacity eligible for ICAP payments makes an appropriate contribution to reliability under stressed system conditions.

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[25] As discussed below, deliverability requirements can take many forms, ranging from the locational ICAP requirements of the NYISO to the CETO/CETL tests of PJM.

2. PJM

The PJM deliverability requirement for ICAP resources tests whether the aggregate of capacity resources can be utilized to reliably deliver energy to aggregate control area load. This deliverability requirement has two components based on probabilistic load and outage analyses. First, the ability of an electrical area to export energy to the remainder of the control area is tested to ensure that ICAP capacity is not bottled. This test ensures that each electrical area is able to export any surplus capacity at peak load (i.e., under stressed system conditions). The failure of a new generating unit to pass this tests implies that it is bottled and that additional transmission must be built for this capacity to be deliverable to PJM load outside the subregion.[26]

This deliverability requirement has two important features. First, all generation subject to the test fails or all generation passes. Second, existing ICAP suppliers are grandfathered so the failure of ICAP resources to collectively satisfy the deliverability test does not affect the ability of incumbents to supply ICAP; it only excludes competition from entrants. Suppose, for example, that PJM determined that 1,000 MW of capacity could be exported from a particular generation pocket and 1,000 MW of capacity existed that had previously been approved as ICAP resources. A new entrant would not be approved as an ICAP resource unless it expanded the transmission system to satisfy the deliverability requirement and thus would be unable to undercut the incumbent ICAP suppliers, even if the entrants full costs were considerably lower than the market price of ICAP demanded by the incumbent suppliers. This grandfathering of incumbents allows generators to enter into multi-year ICAP contracts but it violates the efficient entry condition.

The second reliability test assesses whether energy will be deliverable from the aggregate of PJM resources to the load in the portions of a PJM subregion experiencing a localized capacity deficiency. The second test is based on the Capacity Emergency Transfer Objective (CETO) and Capacity Emergency Transfer Limit (CETL) tests, applied to electrical subareas within PJM. The CETO measures the amount of energy that the subarea must be able to import in order to remain within MAAC reliability criteria. The test is passed if the actual emergency transfer limit (CETL) exceeds the CETO for the area. This deliverability test was historically applied to the service territories of the member Investor Owned Utilities.[27] More recently, PJM has begun to apply the test to other electric subareas within these service territories.[28] While the application of the

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[26] Attachment E: PJM Deliverability Testing Methods.

[27] This made sense from the perspective of the historical role of the required reserve margin as reliability problems arising from transmission constraints internal to the service territory of a single IOU would be internalized by the IOU having the obligation to serve that load and would not impact other pool members.

[28] See PJM, PJM Reserve Requirements, Manual M-20, April 30,2004, pp.23-24. PJM Attachment E: PJM Deliverability Testing Methods.

CETO/CETL test is reasonably clear, the consequences of failure are not because it is the region, not a resource, that fails.

PJM's "Deliverability Testing Methods" state that "Failure of deliverability tests brings at least two different possible consequences. When evaluating a new resource, if the addition of the resource will cause a deliverability deficiency then the resource cannot be granted full capacity credit until system upgrades are completed to correct the deficiency. If the deliverability of PJM degrades, for any number of reasons, failure of deliverability tests may result in a sub-area being unable to receive full capacity credit for remote capacity resources delivered to that subarea."

In the circumstance in which the exit of a generator or load growth cause a load pocket to fail the CETO/CETL test, the PJM deliverability test does not appear to address the question of which resources can qualify as ICAP for LSEs within the region and which LSEs must bear the financial burden of contracting for potentially high cost generation within the region to satisfy the CETO/CETL test. Does failure to contract for high cost generation in a load pocket trigger transmission expansion?

The PJM ICAP deliverability requirement is workable for generation potentially located in generation pockets, as generation sited at such a location would be required to pay for transmission upgrades to expand deliverability if the new capacity otherwise would not make a sufficient contribution to PJM reliability. As noted above, however, the grandfathering of existing capacity under this system potentially deters efficient entry and keeps high cost generation in operation. This ICAP deliverability requirement works less well for incenting generation to locate within high cost load pockets and can break down if such load pockets exist. If a capacity shortage develops within any load pocket within PJM, no new generation might be able to meet the ICAP delivery test unless the shortage within the load pocket were eliminated. The cost of siting generation within the load pocket, or of a transmission expansion to deliver capacity into the load pocket might greatly exceed the market price of capacity elsewhere in PJM, so which LSE must pay for this marginal ICAP? In such a circumstance, no market participant would be willing to incur the cost of siting generation or building transmission to relieve the shortage in the load pocket, but until such capacity was added, the region could not pass the CETO/CETL test.

Suppose, for example, that the cost of new capacity required to satisfy the deliverability requirement within a particular load pocket were $150,000/MW, but the going-forward price of capacity located outside the load pocket was only $5,000/MW. Under the PJM procedures, no new capacity outside the load pocket could satisfy the deliverability test so there would be no ability to undercut ICAP prices demanded by grandfathered incumbents up to $150,000/MW. Moreover, the LSE actually serving load inside the load pocket could have entered into long-term contracts for ICAP with grandfathered resources located outside the load pocket and escape the consequences of the high ICAP prices brought on by the exit of capacity located within the load pocket.

The combined effect of these features could be to exclude all new generation from the ICAP market and to prevent new generation from undercutting incumbent offers unless the entrants fund transmission investments sufficient to reliably deliver energy to aggregate control area load throughout PJM, but the cost of such investments could exceed the price of ICAP.

In practice, these patterns have not appeared in the PJM ICAP market. For reasons that are not always apparent, prices in the PJM ICAP market have been set at very low levels by generation located outside the Eastern PJM load pocket while a large number of units in Eastern PJM are apparently unable to remain in operation at these ICAP prices and have been seeking to exit the market, yet their continued operation would be necessary in order for generation in PJM to satisfy the aggregate deliverability test. These problems in the ICAP market provided part of the impetus for the development of a new ICAP design for PJM, called the Reliability Pricing Model.

3. New York

The New York ICAP system was developed with the Manhattan and Long Island load pockets in mind and with the intent of placing all resource providers on a level playing field. Rather than imposing a control area wide ICAP deliverability requirement, New York has attempted to ensure ICAP deliverability by establishing locational ICAP requirements. LSEs serving load in New York City are required to procure at least 68 percent of their ICAP requirements (or 80 percent of peak load) from NYC resources. LSEs serving load in Long Island are required to procure at least 84 percent of their ICAP requirements (or 99 percent of peak load) from Long Island resources.[29] This system allows ICAP prices in an individual load pocket to rise to the level required to warrant new investment or to keep existing capacity in operation. The advantage of this locational system relative to a PJM-type deliverability requirement is that the price of ICAP capacity within a particular load pocket (Manhattan) can be very high at the same time that ICAP prices are much lower elsewhere (upstate New York) and incumbents and entrants have equal access to the transmission system.

New York has also developed the concept of unforced capacity deliverability rights (UDRs) for new transmission projects that enable power to be delivered into New York City or Long Island from capacity located elsewhere. The construction of additional transmission into Long Island or New York City will not change the locational ICAP requirement. Instead, the transmission project would be awarded UDRs reflecting the ability of the transmission assets to deliver additional power into the ICAP region. A

[29] NYISO Installed Capacity Manual, Attachment B, April 26, 2004. These percentages are not fixed and can change for each capability period.

UDR combined with an upstate ICAP resource would then count as in city or on island ICAP.[30]

The New York locational ICAP system has potential limitations. Perhaps the most important limitation is that the New York City locational ICAP market tended to clear at the price cap set in the Con-Ed divestiture contracts, so the price cap for divested generation has acted like an administratively set ICAP price.[31] A second limitation is that there may be additional load pockets within New York that are not represented in the ICAP system. For example, there is no east of Central East ICAP requirement, yet Central East can prevent Western generation from meeting Eastern load during shortage conditions. There is also a possibility of reliability problems within Long Island or within In City load pockets that would not be reflected in the On Island or In City requirements.

4. NEPOOL

ISO-NE proposed and filed at FERC in 2004 a locational ICAP system that is similar to the system in place in New York. NEPOOL would have four locational ICAP regions, Connecticut, Northeast Massachusetts and Boston, Maine and rest of New England with separate demand curves for each region.[32] As in New York, the ISO-NE demand curve would be implemented in a monthly spot market auction in which each participant is required to offer all of their UCAP resources, with offers subject to mitigation. All capacity must be offered in the ICAP region in which it is located and all participant load would be cleared in the ICAP region in which it is located.[33]

It is noteworthy that generation ownership in these ICAP submarkets is much more concentrated than in New England as a whole. While the HHI for New England is around 750 according to ISO-NE, the HHI in Connecticut was 2300 and over 5300 in Boston.[34]

This version of the NEPOOL locational ICAP system was to include Capacity Transfer Rights across each ICAP interface. CTRs would be a financial instrument that hedges inter-submarket UCAP costs. They would entitle the holder to the difference in the price of UCAP in the UCAP spot auction between the two ICAP regions specified by the CTR. Entities holding CTRs would therefore receive a payment reflecting locational

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[30] See NYISO Services Tariff, Section 5.11.4, Sheets 127-127A; NYISO ICAP Manual, Section 4.14, p. 4-34; and Internal NYISO DC Controllable Line Scheduling, Concept of Operations, May 4, 2004, p. 8.

[31] This situation has changed with the implementation of the demand curve.

[32] Compliance Filing of ISO New England Inc Docket ER03-563, March 1, 2004 Filing Letter, p. 5 (hereafter ISO-NE March 2004). This description covers the ISO-NE proposal as of early 2004. The report does not cover the subsequent evolution of the ISO-NE locational ICAP proposals.

[33] ISO-NE March 2004, pp. 42-44.

[34] ISO-NE March 2004, p. 48.

ICAP differentials. CTRs would also be allocated monthly to loads inside Boston and Connecticut based on existing transfer capability. CTRs out of Maine would be allocated proportionately to generators in Maine.[35] In addition, there would be a special allocation of CTRs to municipal utilities reflecting their historic entitlement to use of the transmission system.[36] Thus, loads inside the Boston and Connecticut pockets would buy a proportion of their ICAP at the rest of New England ICAP price and generators in Maine, an export constrained region, would sell a portion of their ICAP at the rest of New England price.[37] CTRs would therefore be financial instruments like FTRs, but they would hedge inter-regional differences in ICAP prices when constraints on inter-regional ICAP transfer are binding in the UCAP spot auction.

The ICAP prices determined by the ICAP demand curve were to be capped in the import constrained regions with a five-year phase-in, with the cap rising by $1,000/MW month per year.[38] Offsetting this cap would be a $5,340/MW month transition payment to generation in the Boston and Connecticut load zones with a capacity factor of less than 15 percent in 2003. These transition payments would be borne by network load in the import constrained subregion.[39]

The estimated full recovery ICAP price used in determining the ICAP demand curve would have two components. First, it would include the estimated price of new capacity of $6,666/MW month. Second, the estimated infra-marginal energy market revenue of a new GT, $2,100/MW month, would be subtracted, initially yielding an ICAP price of $4,566/MW month at the target capacity level.

The overall ICAP requirement for NEPOOL would be determined and then allocated to the ICAP regions based on peak loads during the prior year. The ISO would then determine the minimum level of ICAP required within each region by removing capacity within a region until the reliability criterion is violated. This requirement would then be translated into UCAP and the locational UCAP requirement would be subtracted from the regional UCAP requirement to determine the amount of UCAP that could be imported into each ICAP region. The ISO-NE ICAP proposal would explicitly result in

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[35] ISO-NE, March 2004, p. 39.

[36] ISO-NE March 2004, pp. 39-40.

[37] This rule in effect transfers part of the value of the transfer capability between Maine and the rest of New England to Maine generators, despite the fact that Maine generators do not pay the embedded cost of this transfer capability.

[38] ISO-NE March 2004, pp. 6, 27-29

[39] ISO-NE March 2004, pp. 6, 29-32 Units receiving the transition payments will be subject to a variety of restrictions, in particular, tighter mitigation of offer prices than other units After the phase in, the ICAP price cap will be removed in the constrained regions and all units will be subject to this tighter mitigation. ISO-NE March 2004, p. 49.

cascading of locational ICAP prices.[40] This is important for ensuring rational prices when excess capacity is available within a load pocket.

5. Comparisons and Extensions

An important advantage of a locational ICAP system relative to a PJM-type deliverability system is that it permits a market premium to be reflected in the ICAP payment to generation located within high cost load pockets, making it economic for such capacity to remain in operation despite lower ICAP prices in other regions. This feature of an ICAP system also ensures that a control area wide ICAP shortfall does not result whenever it becomes uneconomic to build new capacity within one or more load pockets at the regional ICAP price.

One limitation of a locational ICAP system is that an ICAP requirement for highly concentrated load pockets combined with an administratively determined ICAP price cap essentially amount in the short run to an administratively determined capacity payment, with very little role for markets. The reality is that the Con Ed locational ICAP payment generally clears at the price cap set in the Con Ed divestiture contracts. This kind of outcome is even more likely in smaller load pockets with even fewer competing suppliers. In the long run in which loads can contract with entrants for new capacity, there is much more potential for competitively determined ICAP prices, even in concentrated load pockets, but this requires that ICAP buyers have long-term load-serving obligations that permits them to enter into long-term ICAP contracts, a topic which is discussed further in Subsection D below. The NYISO ICAP demand curve discussed below potentially addresses this situation to a degree by allowing locational ICAP prices to vary in a range with changes in supply.

There are two potential extensions of the NYISO/ISO-NE locational ICAP systems to address the problem of intra-zonal generation pockets. One approach would be to add an intra-zonal deliverability requirement to the locational system. Thus, generation located on Long Island would only qualify as ICAP if it satisfied an intra-Long Island deliverability requirement. Such an approach could work if the goal is to ensure that developers do not site a disproportionate amount of new generation within a generation pocket and would incent developers to spread out new generation. Such a system could, in principle, however, deter efficient entry. Moreover, such an approach would not work as well, and have limitations similar to the PJM system, if reliability required incentives for new generation to locate within specific load pockets within a zone.

Second, by combining a locational ICAP system with shortage pricing within load pockets, one could use energy market revenues to improve the incentives provided by an

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[40] ISO-NE March 2004, pp. 35-39

ICAP system. It was noted above that the locational incentives provided by an ICAP system become more important as the proportion of revenues that marginal generator receives from the ICAP system rises. If the marginal generator can obtain substantial revenues from the energy and reserve markets if it locates within constrained load pockets, this would tend to limit the need to reflect these incentives in the ICAP system itself. Thus, one can think of the evolution of NYISO reserve markets, shortage pricing and reserve demand curve not as obviating the need for an ICAP market but as tending to ensure that the marginal generator recovers an appreciable proportion of its going-forward costs in energy and reserve markets and is thus exposed to locational signals in these markets.

C. Outage Performance

A second performance issue arising under ICAP systems is that rules are needed to ensure that the capacity receiving ICAP payments is sufficiently reliable that it is available to meet load under stressed system conditions. As with ICAP deliverability requirements, outage standards are necessary because generators receive ICAP revenues whether or not they actually operate, so an additional mechanism is necessary to ensure that generators receiving ICAP payments have incentives to minimize forced and maintenance outages. This incentive problem has been addressed by the development of the UCAP system which is currently applied throughout the Northeast.

UCAP systems calculate an ICAP requirement based on projected generation outages based on historical performance as discussed above. The amount of ICAP each supplier is entitled to sell is then scaled down based on the supplier's historical outage performance. The scaled-down capacity is called UCAP, and it is UCAP that LSEs are required to purchase. Under the existing UCAP systems, the UCAP capacity of each supplier is fixed prior to each auction based on the forced outage performance of that supplier's units during a prior period. ISO-NE calculates UCAP ratings monthly based on a rolling 12-month historical performance.[41] PJM calculates UCAP ratings for each ICAP interval.[42] The PJM UCAP rating is calculated on a rolling 12-month average for the 12 months ending 2 months prior to the billing interval.[43] The NYISO calculates UCAP based on the average EFORd calculated for the six most recent 12-month rolling average periods.[44] NYISO UCAP is calculated separately for generation in New York

[41] NEPOOL Manual for Installed Capacity, p. 3-10, January 1, 2004; New England Power Pool, Market Rule 1, Section 8.3.6, Sheet 87.

[42] The PJM ICAP intervals are June 1-September 31, October 1- December 31, and January 1 to May 31.

[43] PJM Manual, Capacity Obligations, Section 1, p. 6, June 1, 2005; PJM Reliability Assurance Agreement, May 17, 2004, Sheets 15, Schedule 5.1, Sheets 42-43.

[44] NYISO ICAP Manual, Section 4.5, p. 4-12; NYISO Services Tariff, Section 5.12.6(a), Sheets 135B-135B.01.

City, Long Island, and the rest of state, so locational UCAP requirements are established. Under all three systems,

$$UCAP = ICAP * (1 - EFOR_d)$$

Units with poor historical forced outage performance therefore are able to sell less UCAP per megawatt of physical capacity and will earn less money in the ICAP market in the future, motivating them to maintain high levels of availability.

ICAP systems also restrict the scheduling of maintenance outages by ICAP resources. The NYISO requires that ICAP suppliers provide the NYISO with advance notification of outages and outages are subject to being rescheduled by the NYISO.[45] PJM requires that ICAP generators submit schedules of planned outages to PJM for coordination with other generation and transmission outages.[46] In addition, PJM deducts capacity that is unavailable due to maintenance during PJM's peak season (roughly mid-June to mid-September) from the resources' unforced capacity.[47] ISO-NE also requires that ICAP resources notify the ISO in advance of their proposed maintenance outage schedules and these outages are subject to being rescheduled.[48]

One negative side effect of UCAP systems is that generators appear reluctant to declare forced outages because of the impact or outages on their ICAP revenues. Instead, they may drag on the system when capacity having operating problems is dispatched to meet load. It is therefore desirable, in combination with a UCAP system, to either have significant penalties for failing to follow dispatch instructions or some other system of sanctions. Outages and deratings that occur on a high load day are unfortunate from a reliability standpoint regardless of the market design but their reliability impact is exacerbated if the system operator is not informed of them and the units are unable to perform as instructed.

Moreover, since the EFORd forced outage data are employed in the Monte Carlo analysis used to determine ICAP requirements, the incentive of generators to overstate availability can potentially impact reliability by leading to understated ICAP requirements. NYISO audits identified such overstated unit availability in the GADs data supplied by some generation owners, leading to a material increase in the ICAP requirement when the higher EFORd outage rate was used in the Monte Carlo reliability analysis.[49]

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45 NYISO ICAP Manual, Section 4.3.

46 PJM Reliability Assurance Agreement, May 17, 2004, Section 9.2.

47 PJM Reliability Assurance Agreement, May 17, 2004, Schedule 8.

48 ISO-NE ICAP Manual, Section 3.3.

49 NYSRC 2004, p. 4, 23.

A second issue is whether the EFORd index employed by UCAP systems to measure generator availability provides sufficient performance incentives for baseload units.[50] The EFORd UCAP systems employed in the Northeast essentially cause an ICAP supplier to receive the ICAP payment in proportion to its availability. Thus, if an ICAP unit were on line 6,650 hours, and out due to forced outage in 350 hours, it would have a 95 percent EFORd rating and would be paid for 95 percent of its capacity (or one can think of this unit as being paid 95 percent of the ICAP price). This would be the case whether the 350 hours of forced outage occurred in the spring when the price of power was $12/MWh and the outage had no reliability impact or if the 350 hours of forced outage occurred in July, the average LMP price was $500 and the outage resulted in load shedding.

Similarly, the incremental value of staying on line over a day is relatively small under a UCAP system. For a unit with around 7,000 hours combined on line and out of service, the impact on the unit's EFORd of a 24-hour forced outage would be a little more than .3 percent, so would cost a little less than $350/MW for a New York City unit with a $100,000/MW UCAP price. The UCAP system by itself therefore provides baseload units with relatively little incentive to make themselves available under stressed market conditions.

One can think of the NYISO shortage pricing rules as one way of addressing this potential incentive problem by attempting to ensure that the marginal ICAP supplier recovers a meaningful proportion of its going-forward costs from the energy market during shortage conditions. Units whose 350 hours of forced outage occur during reserve shortage hours around the summer peak could forgo much more than the outage cost under the UCAP system.

In Fall 2004 ISO-NE proposed a series of revisions to its locational ICAP market designed to address this problem by providing incentives for ICAP resources to be available during stressed system conditions. The need of ICAP systems to develop performance incentives relating to generator outages is closely related to a third issue, generator availability.

D. Availability Limitations

The existing ICAP markets in the Northeast focus on transmission system deliverability and operational forced outages and deratings to measure generator availability under stressed system conditions. Experience has shown, however, that generation may be

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50 A related issue which does not appear to be a problem would be a potential for market participants to simply not offer capacity in real-time without declaring a forced outage. The ISO rules appear to deter such behavior. ISO New England market rules call for imposing a sanction of an amount up to the deficiency charge and imposing a financial sanction equal to the corresponding real-time LMP price. New England Power Pool Market Rule 1, Appendix B, p. 307.

deliverable and in perfect operating condition yet unable to meet load under stressed system conditions because of other availability limitations. There are at least four kinds of problems that can produce this result: fuel availability, energy limits, restrictive start-up conditions, and restrictive availability conditions. The first three of these limitations have figured prominently in reliability crises over the past several years in the Northeast, California and Texas, while the fourth may be of increasing importance as renewable resources are added to the ICAP resource mix.

1. Fuel Availability

While one often thinks of the summer peak as the time of maximum stress on the transmission and generation system, several reliability crises have arisen in recent years during the winter months. First, most of the load shedding in California during the 2000-2001 crisis occurred during the winter, not the summer. Second, the last time load shedding was necessary on a wide scale in PJM was during the winter of 1993-1994. Third, during the winter of 2003-2004 NEPOOL came uncomfortably close to requiring load shedding during a winter cold spell. Fourth, Ercot's worst recent reliability crisis came during the winter of 2003, not during its summer load peak.

A problem common to all but perhaps the PJM case was that high demand for electricity was accompanied by a high demand for gas for space heating. This high demand for space heating drove gas prices to very high levels, greatly raising the cost of electricity from gas-fired generation and limiting its availability. Thus, in California during the winter of 2000-2001, unusually high gas demand both in California and the west in general driven by low hydro conditions led to very high gas demand and gas prices as shown in Figures 8 and 9.

Figure 8
California Gas Demand and Prices

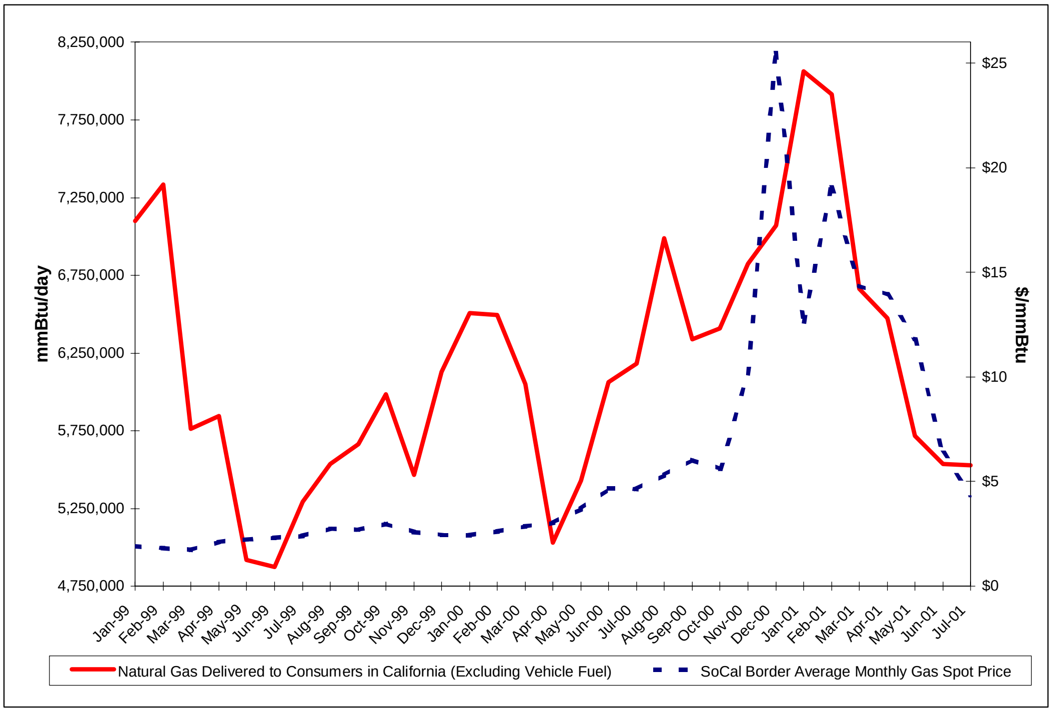
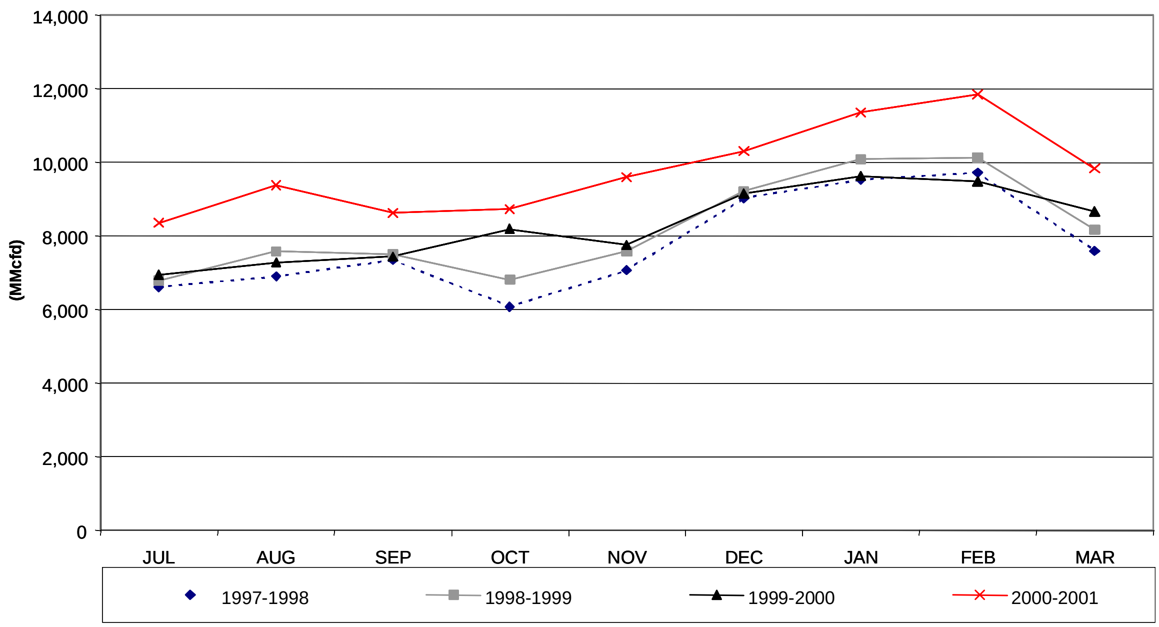


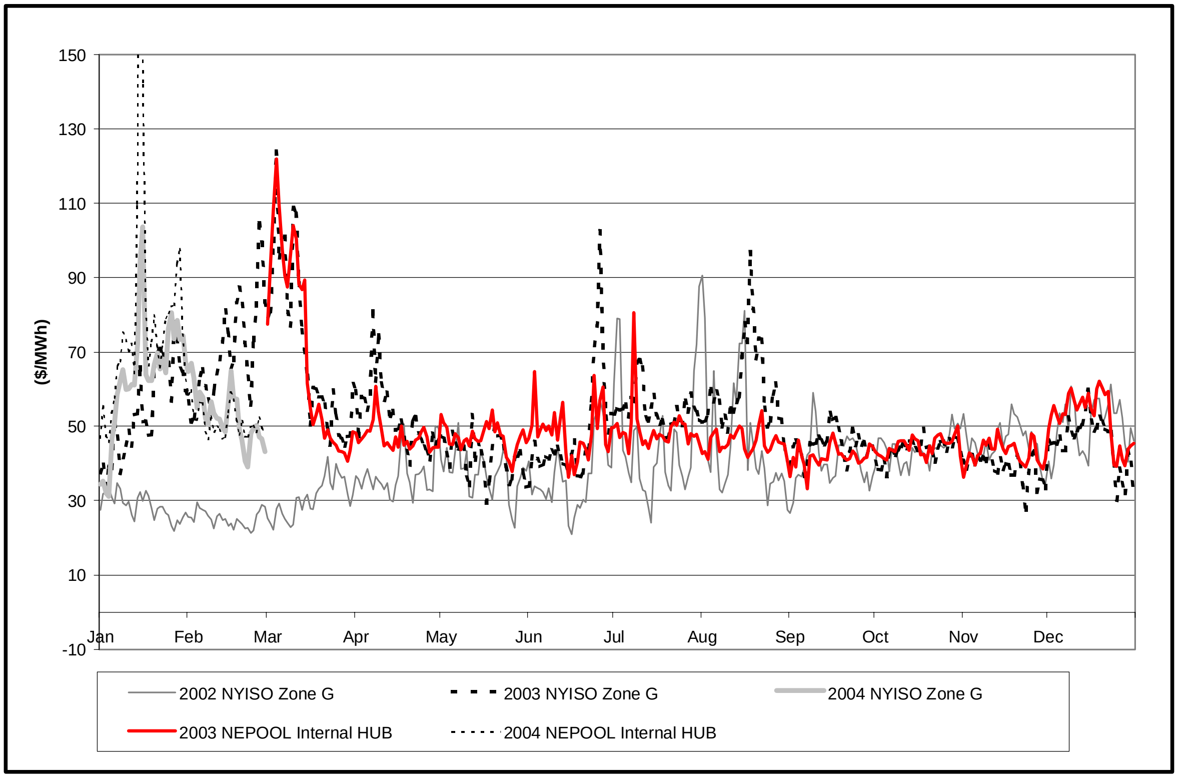
Figure 9
Average Daily Natural Gas Delivered to Consumers in CA, OR, WA, AZ, NV and NM (Excluding Vehicle Fuel)



Source: Table 22 (appended).

Similarly, Figure 10 shows that during 2002 and 2003, high power prices and price spikes have been more common in the New York and particularly New England electricity markets in the winter than in the summer due to high gas prices.

Figure 10
NYISO Hudson Valley (Zone G) and NEPOOL Hub 2002-2004
Daily Average DAM Prices



Aside from the price impact of the gas shortages, there are three areas of potential reliability impacts of gas shortages under ICAP systems. First, there can be times that gas-fired generation at some locations simply cannot consume any more gas at any price, because any higher burns would drop pipeline gas pressure below the critical level leading to generation trips and immediate load shedding.

Second, most existing ICAP systems do not require gas-fired generation to contract for firm gas transmission with either the local distribution company or the interstate pipeline. Under traditional LDC pipeline curtailment rules, a lack of firm gas transmission service would mean that a gas-fired generator would not be able to use gas to generate electricity during periods of gas curtailments. In practice in many regions today, gas availability is determined by the market, not curtailment rules. In these areas, a generator lacking firm gas transmission service can still generate during periods of gas shortage by buying gas at the market-clearing price.[51] The gas system is balanced by customers choosing not to buy gas at high prices rather than by curtailment priorities. Conversely, a generator having firm gas transmission service may sell its gas on days with high gas prices if the electricity price is not sufficiently high to warrant operation.[52] Overall, physical curtailment is only a concern today in areas with generation served under traditional curtailment rules (at the LDC level). Generators are of course not precluded under an ICAP system from contracting for firm gas transmission service, but an ICAP system may diminish their incentive to do so. The crux of an ICAP system is that energy market revenues under shortage conditions are limited by price caps and marginal capacity is kept available by the ICAP payment. If the ICAP payment does not depend on having firm gas supply, the incremental energy market revenues may not be sufficient to cover the cost of contracting for firm gas supply and generators may not do so.[53]

Third, gas market price volatility under stressed market conditions may cause gas fired generation lacking dual fuel capability or hedged gas supply to withdraw from the day-ahead electricity market. As noted above, any individual gas fired generator can in principle be assured of obtaining gas under market based gas systems by offering to pay the market clearing price of gas. The generator would then be able to supply electricity at a cost commensurate with the market price of gas. There is nevertheless a reliability problem. In aggregate it is not true that gas fired generators collectively can acquire all the gas they need at the market clearing price as the gas demand of non-generators may at some demand level become highly inelastic in the short run as generators increase their gas consumption at the expense of other consumers.[54] This may lead to extreme gas price volatility that may drive unhedged generators out of the gas market and forward ICAP

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[51] Thus, while New England gas LDCs and interstate pipelines curtailed non-firm transmission customers during the January 2004 cold spell, generators lacking firm transmission were still able to obtain gas by purchasing it from entities that had firm transmission. See ISO New England, Inc., Market Monitoring Department, "Interim Report on Electricity Supply Conditions in New England during the January 14-16, 2004 `Cold Snap'," May 10, 2004 (hereafter ISO-NE May 2004). Similarly, although there was generally no non-firm transmission service available to California on El Paso or Transwestern during the winter of 2000-2001, customers lacking firm transmission service could readily acquire daily, bid week, or term gas at the California border (SoCal Border pricing point).

[52] While ISO-NE found that gas-fired generation with firm gas transmission was somewhat more available than gas-fired generation lacking firm transmission, the difference was not dramatic (56 versus 42 percent) and may have been due to other factors (i.e., the gas-fired generators may have had firm gas contracts because they are cogeneration units that operate without regard to the electricity market). See ISO-NE May 2004, pp. 68-69, 72, 141.

[53] The MAPP reserve sharing program requires either dual fuel capability or firm gas supply and firm gas transportation for capacity to qualify as ICAP during the winter season. MAPP Reliability Handbook, Section 3.4.7.2.1.

[54] The price responsiveness of non-electric generator gas demand may also vary substantially from LDC to LDC. Some gas LDCs may serve a lot of price-sensitive industrial demand that will reduce consumption as prices rise, while other LDCs may serve largely residential demand that is price-inelastic in the short run.

contracts would not ensure that enough gas would be available to maintain electric system reliability.

The potential for gas price volatility to reduce generation supply has several elements. First, consider the position of a gas-fired generator operating in a power market that closes after the gas market closes. If the generator purchases gas in the regular day-ahead gas market before offering supply in the day-ahead electric market, the generator risks buying high priced gas that turns out to be uneconomic in the power market. Indeed, this would be likely if gas-fired generators collectively offered whatever it took to buy gas in the day-ahead gas market and then sold their excess gas in the in-day gas market. Alternatively, a generator could offer electricity at a high price in the electric market and then buy gas in-day to cover this position if the generator's offer cleared in the day-ahead electricity market. If gas prices are extremely volatile and the gas market thin and illiquid, however, this strategy could be risky with a substantial possibility of having to pay a much higher than expected gas price in order to cover the electric market position. The same situation could arise if the day-ahead electric market cleared prior to the day-ahead gas market, the generator could sell power before buying gas, but the generator would then risk not being able to purchase gas at a price low enough to make money generating electricity.[55] The best strategy might therefore be to offer power in the day-ahead market at $1,000/MW and to only run to cover this position if is possible to buy gas at a sufficiently low cost. If the gas price were too high, the generator simply would not run.[56]

It may at first appear that these reliability impacts are addressed by the must offer requirement of ICAP systems, but this is not the case. A common feature of the NYISO, ISO-NE and PJM ICAP markets is that ICAP resources not available as a result of a forced or maintenance outage are obliged to offer their capacity into the day-ahead market of the control area for which they are an ICAP resources.[57] Gas-fired generators lacking dual fuel capability, lacking firm gas supply, or unwilling to risk purchasing extremely expensive gas are therefore required by the market rules to offer their ICAP capacity in the day-ahead market. If these units instead take a forced outage, they suffer a revenue impact in the next ICAP auction. We noted above, however, that the financial

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55 The market power mitigation system could be another source of risk if it does not track contemporaneous gas prices and generators buying gas on day t to cover generation on either day t or t+1 risk having their offer prices mitigated based on the gas prices reported for day t-1.

56 These kinds of concerns appear to have reduced the supply of gas-fired generation in New England during the January 2004 cold snap. Gas was available for purchase at a price, but the intra-day gas market was thin, and the price volatile and unpredictable. As a result, much gas-fired generation was unavailable due to a "lack of gas supply." See ISO-NE May 2004, pp. 44, 49-51, 56-65, 104-106.

57 NEPOOL Manual for Market Operations p 2-11. PJM Operating Agreement, Section 1.10.1A, Day-Ahead Energy Market Scheduling, Sheet 93; NY ICAP Manual, Section 4.8, p. 4-14; NYISO Services Tariff, Section 5.12.7, Sheets 135c, 135d.

impact of such outages could be very small for a baseload unit and much lower than possible losses from selling uneconomic power in the day-ahead market.

More significantly, from a reliability perspective, the ability of units to declare a forced outage when not available due to fuel supply constraints is not consistent with the reliability analysis on which the ICAP analysis is based. Control area ICAP requirements are based on probabilistic analyses of available generation, transmission and load.[58] Critically, the reliability analyses assumes that forced outages are independent events. Because forced outages are modeled as independent events, it is unlikely in these reliability analyses that a large number of generating units will suffer a forced outage on the same day, so many units with low forced outage rates enable a control area to be confident of satisfying its one-day-in-ten-year reliability criteria. If the "forced outage" is actually a failure to offer capacity due to lack of gas supply combined with a lack of dual fuel capability, then the "forced outages" are not appropriately modeled as independent, however, instead they may be highly correlated across many gas fired units lacking dual fuel capability and the control area may have a much higher reliability risk than indicated by the probabilistic analysis used to develop the ICAP requirement. Moreover, as noted above, the actual ICAP revenue impact of a 72-hour forced outage on a baseload gas unit would be very small, providing little incentive for the ICAP supplier to incur substantial costs or risks in order to be available.

The mere fact that reliability problems can emerge under extreme gas market conditions is not necessarily a limitation of an ICAP system as these reliability problems could simply be an unavoidable real-world possibility. The underlying problem is that an ICAP system is less effective than forward energy contracts and uncapped day-ahead and real-time prices in providing an incentive for market participants to address the potential reliability problems so that an ICAP system may give rise to reliability risks that would not exist under an energy-only pricing system.

There are at least three actions that gas-fired generators could potentially take to improve overall reliability that could be impacted by reliance on ICAP versus energy market pricing to assure electric system reliability. First, gas-fired generators could develop and maintain dual-fuel capability. Second, they could inject gas into production area storage, or contract for LNG deliveries into storage making more gas available at times when the pipeline system is constrained. Third, they could contract for new gas transmission capacity into the region, increasing delivery capacity. None of these actions will be incented by a conventional ICAP system.

Often, the best solution to winter gas supply reliability and the market impacts of gas shortages is the development of gas-fired generation with dual fuel capability. At the time of ICAP market implementation in the Northeast, a substantial proportion of the

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58 See Subsection E below.

former utility gas-fired generation had dual fuel capability and routinely switched to oil during periods of high gas demand. It is not clear, however, whether the ICAP-based reliability mechanisms in the Northeast will sustain this capability. The ICAP systems currently do not require dual fuel capacity and a considerable proportion of the gas-fired generation that has been built in the Northeast since 1998 lacks dual fuel capability, having neither permits nor oil capable burners. Even in those cases in which generating units were permitted as dual fuel, the generators have not in all cases either installed liquid storage or filled the storage. Worse, from a reliability perspective, there is a prospect for material amounts of the existing dual fuel capable generation being shut down and replaced with gas-only generation having a lower heat rate.

It is noteworthy that California, like the Northeast, used to have substantial fuel switching capability in its electric generating resources. During the 1994 drought in the west, there was substantial fuel switching by California electric generation that did not occur during 2000-2001. Table 11 shows that during the winter of 2000-2001 total electricity generation at the plants in San Diego and Northern California having dual fuel capability was somewhat higher than the total generation at these plants during the same period in 1993-1994.[59] There was a dramatic decrease, however, in the amount of oil-fired generation between 1993-1994 and 2000-2001. There was almost no oil-fired generation during the winter of 2000-2001. This decrease in oil generation increased gas demand from electric generation, raising gas prices.

Table 11
Fuel Shifting in California

	November 1993 – April 1994		**November 2000 – April 2001**	
	Total MWh	**Oil MWh**	**Total MWh**	**Oil MWh**
Northern California				
Potrero 3	529,329	20,580	536,859	0
Hunters Point	629,532	137,329	359,412	0
Pittsburg	4,420,365	251,551	5,402,515	0
Contra Costa	2,111,946	121,611	1,853,595	0
Moss Landing	5,061,748	318,929	3,876,883	0
Morrow Bay	1,774,232	112,484	2,552,311	0
Total	**14,527,152**	**962,484**	**14,581,575**	**0**
Southern California				
Encina	1,261,524	610,662	2,488,493	52,831
Source: EIA Form 759.				

Part of the change in fuel switching behavior in California between 1994-2001 was due to changing environmental limits and unit capabilities, but another more subtle factor were the changes in gas pricing. In 1994 SoCalGas consumers could buy all the gas they wanted at the regulated price and when there was not enough at the regulated price, some customers, including electric generating customers able to fuel switch, were interrupted. As a result, the electric generators switched to oil fuels every time the gas market got tight in 1993-1994.

By 2000-2001, however, SoCalGas, like many other gas distribution companies had many customers on its system that paid the market clearing price for the gas they consumed. Despite gas demand by electric generation that was far above normal levels due to a combination of reduced hydro generation, nuclear plant outages and cold

[59] In addition, a number of plants in the LA Basin generated small amounts of power using oil in 1993-1994, and none in 2000-2001.

weather, SoCalGas did not have to rely on administrative curtailments to balance supply and demand during the winter of 2000-2001. In 2000-2001, non-core gas consumers in California could generally buy all the gas they wanted at the market clearing price. As long as there was enough gas at the market-clearing price, non-core customers were not interrupted, but the market price rose until non-core gas customers reduced their consumption, making gas available on the spot market. As a result, environmental rules permitting electric generators to fuel switch only when curtailed, rarely came into play because deliveries were rarely subject to curtailment, the gas price rose until the market cleared. The only reason any fuel switching occurred in San Diego during 20002-2001 is that there was no separate locational gas price for San Diego on the SoCalGas system, but San Diego had a separate set of delivery constraints that became binding at times, requiring gas curtailments at the same gas price that cleared the market elsewhere on the SoCalGas system.

Gas-fired generators in the Northeast have generally not encountered these kinds of environmental restrictions on fuel switching but that will potentially end in the near future when some NOx restrictions are extended from the summer to year around.

It is, therefore, important to recognize that with environmental restrictions on fuel switching by gas-fired generation, the gas market price can rise far above the cost of oil before fuel switching occurs. The system may still be reliable in principle if fuel switching can occur if sufficient gas is not available and load shedding would otherwise be required,[60] but market prices can become extremely high under such rules, as was seen in California. Because gas demand may not be highly elastic during winter conditions, the gas price can perhaps become so high that electric generating companies are reluctant to buy gas at those prices out of a fear that they will not be able to recover those costs in the power market.

Beyond the mere possession of dual fuel capability, reliability during winter conditions can also be impacted by the amount of oil fuel in storage. Possession of dual fuel capability by gas-fired generation does not help reliability if the fuel oil stocks are not sufficient to keep the generation burning oil. Problems with oil stockpiles have been an issue in most winter reliability crises. Thus, in Ercot in early 2003, the combination of cold weather and an ice storm in North Texas led to very high gas demand and high gas prices during a period of unusually high winter electricity demand. Many units had dual fuel capability but the severe weather and the uncertainty as to when the cold would abate required husbanding of oil fuel for generation because the impassible roads meant there was no ability for trucks to replenish fuel stocks as they became depleted.

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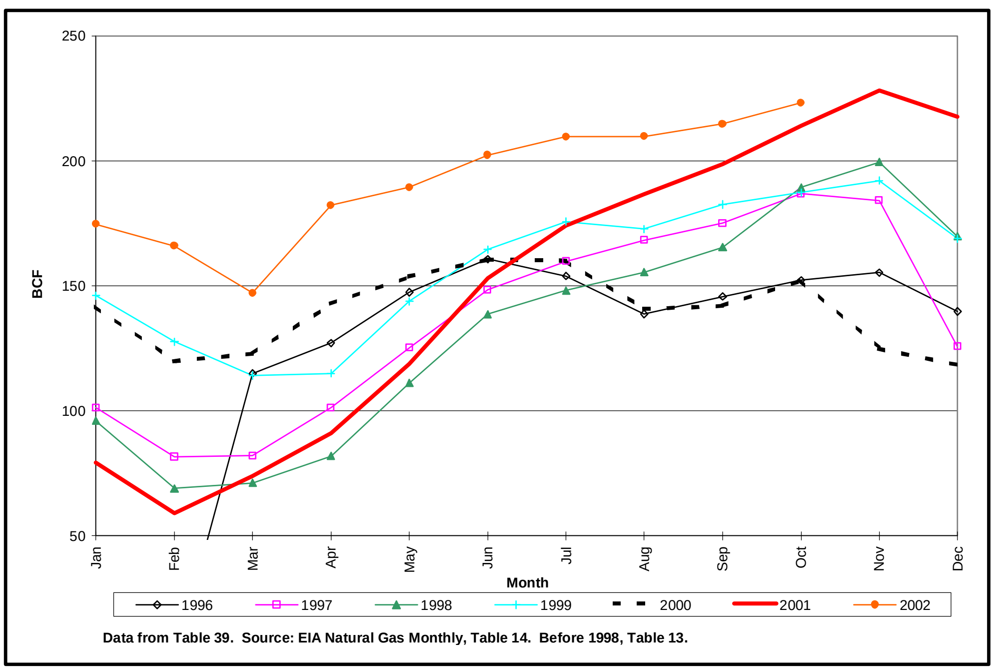
60 It is important for the ISO to coordinate operations with the affected gas distribution companies in these circumstances. Unanticipated ramp ups of electric generation can cause reliability problems on the gas distribution system and dual fuel units cannot instantly switch between gas and oil.

PJM had a similar problem in 1994 when frozen coal piles were accompanied by frozen rivers and ice covered roads that hindered resupply of oil stocks, leading to rolling blackouts by Pepco, PSE&G, Baltimore Gas & Electric, Jersey Central Power, and Vepco. Similarly, ISO-NE reported losing at least 100 MW of oil-fired generation during the January 2004 cold snap due to lack of fuel and additional outages of oil-fired and dual fuel units may have been related to petroleum fuel constraints.[61]

A second potential incentive problem is that the ICAP systems such as those in place in the Northeast do not require generators to put gas in consumption area storage to meet generation demand when the gas pipeline system is constrained, but availability of storage gas can be important in meeting load. In Southern California during 2000-2001, for example, the non-core gas customers as a group entered the winter with no gas in storage and therefore no ability to cushion themselves against high gas demand and daily gas balancing rules. This problem would not have been corrected by a conventional ICAP system, but forward contracts for power during the winter months would likely have incented the gas-fired generators to have put gas in storage during the summer to hedge the cost of covering the forward contracts. In New England, LNG terminals provide the equivalent of underground gas storage but the ICAP system provides no incentive for power generators to contract for LNG capability.

Figure 12
Working Natural Gas in Underground Storage at End of the Month
California (Bcf)



61 ISO-NE May 2004, pp. 31, 94-96, 99.

Finally, an ICAP system does not incent gas fired electric generators to enter into firm contracts for new gas transmission capacity. While power generators helped finance new gas pipeline construction in California beginning in 2001, these contracts were driven by high energy prices and forward contracts not an ICAP system. A new generator that will obtain most of its revenues from the ICAP market or from summer operation, will have little incentive to contract for firm gas transmission capacity to ensure availability of low cost gas in the winter.

There are several ways to address these kinds of fuel supply constraints. One approach would be to add fuel availability requirements to the ICAP program. MAPP has such requirements in its reserve sharing program. The MAPP reserve sharing program requires either dual fuel capability or firm gas supply and firm gas transportation for capacity to qualify as ICAP during the winter season.[62] In addition, MAPP requires that units have sufficient fuel storage to enable the unit run during the 4 peak hours five days in succession.[63] A second approach would be to apply some form of derating to resources based on their historic availability during peak conditions. Thus, gas-fired generation that is unavailable during the winter peak might suffer a derating in addition to the random outage derating reflected in the EFORd. In reviewing the January 2004 cold snap, ISO-NE has mentioned the possibility of adjusting its UCAP rating system to more heavily weight outages during peak periods,[64] and ISO-NE subsequently introduced proposed changes to its locational system that would more closely tie ICAP revenues to generator performance during such stressed system conditions.

A third approach would be adoption of a market design that places greater emphasis on energy market margins to provide performance incentives. If electric prices were to rise during stressed winter conditions to levels reflecting spot gas prices and limited oil fuel stocks, the resulting high power prices would incent gas fired generators to maintain dual fuel capability and incent dual-fired generators to maintain adequate fuel stocks. The potential for high gas prices would incent market participants to fill storage and contract for firm gas transmission. This approach may be difficult to apply, however, in combination with locational market power mitigation utilizing cost-based offer caps if the relevant generators have locational market power. Intraday gas markets can be thin, and even day-ahead gas markets are thin at some locations, making it difficult to accurately apply offer price mitigation based on spot gas prices during winter conditions when the market price of gas can be very volatile. Moreover, since FERC actions in the California refund case did not allow power generators selling their output in the spot market to retain the benefits from having contracted for firm gas transmission, storage or

62 MAPP Reliability Handbook, Section 3.4.7.2.1.

63 MAPP Reliability Handbook, Section 3.4.7.2.1.

64 ISO-NE May 2004, p. 144.

having purchased gas forward, it is uncertain whether generators will incur such costs in the future unless they are hedging a forward power contract.

2. Energy Limits

The analysis of ICAP requirements and reliability by Eastern ISOs is focused on having enough capacity available to meet demand over short system peaks. Thus, an ICAP reliability analysis normally does not ask whether there is enough energy available to meet load over the year. An important feature of the western electricity crisis over the period 2000-2001, however, was that it evolved from a capacity shortage in the summer of 2000 into an energy shortage during the winter of 2000-2001.[65] The source of the problem was that the capacity reductions were concentrated among baseload supply, hydro and nuclear generation, which disproportionately reduced the supply of energy. While part of this energy could be made up by coal and baseload gas units, the magnitude of the energy shortage was such that units with annual operating hour limitations were run until they exhausted their limits and high emission gas fired units were run until NOx allowance requirements effectively precluded further output. Moreover, the need to replace so much baseload power with gas-fired generation contributed substantially to high gas demand that led to transmission constraints on gas deliveries. A different kind of analysis than is typically undertaken in ICAP modeling would be required to assess the risk of energy shortages arising from the Western hydro cycle or from multiple nuclear plants outages for a prolonged period within a constrained region or analogous prolonged energy-reducing events (such as a prolonged outage of a major transmission line used to import power).

One way to address energy, rather than capacity adequacy, would be through forward energy contracts that would incent suppliers to take steps to ensure their ability to cover their position following outages. Alternatively, these risks could be analyzed and addressed through the ICAP market. The ICAP market might, for example, either restrict participation by units with very low levels of hourly energy availability or apply a scale that reduces the ICAP payment to generators with annual energy limits below some threshold. The MAPP reserve requirements have an energy availability provision, requiring that generation other than internal combustion units have permits allowing for at least 500 hours of operation, but this limit is too low to ensure that sufficient output would be available during a sustained energy shortage of the kind to which the West is vulnerable.[66]

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[65] The energy shortage was exacerbated by the low level of forward hedging of energy prices, which undermined the solvency of the largest LSEs, further exacerbating the energy shortage when qualifying facilities were not paid for their output and subsequently reduced output or ceased operation.

[66] MAPP Reliability Handbook, Section 3.4.7.1.1.

One problem with addressing energy adequacy through an ICAP market is that reliability does not require that all generation have the ability to run for 6,000 hours per year, it just requires that enough generation be available to avoid running into energy constraints. The ICAP market is not well suited to providing these kinds of incentives because ICAP requirements apply to all units. Imposing a requirement that all ICAP resources be capable of running for 3,000 hours a year, for example, could greatly magnify capacity costs because much low-cost capacity would be excluded from the ICAP market and higher-cost capacity would need to be built and paid for.

Similar issues can exist for resources with intra-day energy limits such as pumped storage. Both NYISO and ISO-NE currently qualify pumped storage units as ICAP providers despite the fact that the units do not produce any net energy. The NYISO and ISO-NE ICAP rules require only that the units be able to operate for at least four consecutive hours each day.[67] While pumped storage units are very valuable in their current proportions in providing reserves and meeting peak load, there is a potential for technology to produce a greatly expanded supply of short duration energy that would qualify for large ICAP payments but have little value.

3. Start-Up Conditions

The ICAP systems in the Northeast require that ICAP resources offer their capacity in the day-ahead market. It is not always understood, however, that the generators may accompany those offers with start-up times greater than 24 hours so that the capacity is effectively not available for the next day.[68] This kind of offering behavior can be particularly common for rarely used units that are not expected to operate in the near future and are therefore not manned. In these instances, the long-start up times are submitted to enable the plant operator to recall employees and then start the units. The same kind of behavior prevailed prior to deregulation. Some of the problems during the 1993-1994 PJM cold snap were due to misforecasting of demand and an inability to get units not normally used in the winter manned and on-line. The problem also arose in Texas during the winter of 2003 when some new combined cycles were not available because they had not prepared for such low temperatures, while units normally used for summer peaking had been mothballed for the winter and could not come on-line in time when weather forecasts changed.

Long start-up times can have reliability implications, however, as was seen on May 7 and 8, 2000 when a sudden change in weather forecasts in the northeast caused

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[67] NYISO Service Tariff, Section 2.49b, Sheet 36A and 2.74c, Sheet 43; NYISO Installed Capacity Manual, Section 4.8.2; and ISO New England Installed Capacity Manual, Section D1.1.5 and Attachment D, pp. DA-8 and DA-9.

[68] This capacity can be committed by the ISOs but only if they foresee a reliability problem several days in advance.

PJM, New York and New England to be generation short. The NYISO tracked the changes in the weather forecast and by Sunday had a high load forecast for Monday but the NYISO could not commit units with 72-hour start times (on Sunday to be available on Monday), yet these units qualified for full ICAP payments.

Some of these reliability problems arising from demand surprises are unavoidable, but they can be exacerbated by an ICAP system. If most of a high cost rarely operated unit's revenues come from the ICAP market and those ICAP market revenues will be received even if the unit is unmanned and requires a 72-hour start-up notice, the unit owner would have little incentive to staff the unit during normally low load periods and the unit may not be available to meet reliability surprises in the fall, winter or spring. Conversely, if that unit were dependent on high prices in the energy market during shortage conditions for its revenues, or if it had signed forward call contracts that it needed to cover, the unit owner would be more willing to incur higher costs in order to make the unit available to operate on a shorter term basis.

An ICAP system could even potentially sway the choice of generation owners of which units to retire and which to keep in mothballs away from quick start units, if it would be cheaper to keep an old oil or coal-fired steam unit unmanned and in mothballs with a 72 hour start up time. These kinds of incentive problems can in principle be addressed by modifying the ICAP system so that ICAP payments are tied to actual performance during stressed system conditions.

4. Restrictive Availability Conditions

A final limitation of ICAP systems is their application to resources with restrictive availability conditions, such as wind and solar. While energy limited units have the ability, given an appropriate market design, to ensure that their limited energy is used during peak load conditions, wind and solar units are subject to random availability limits. The treatment of wind units under ICAP systems is particularly problematic as the availability of wind energy may be inversely correlated with peak demand. Thus, wind energy output at some projects may be likely to be lowest on hot humid windless summer days when air conditioner load is at its maximum. Solar energy output is likely to be better correlated with peak load conditions, at least in the summer but it may not be much help during winter peaks.

While the non-availability of wind energy can be treated as forced outages under ICAP systems, this is not sufficient for the purpose of reliability analysis. As noted above with regard to fuel availability, forced outages are treated as random events in the reliability analysis used to develop ICAP requirements, but this treatment will not be accurate if wind energy non-availability is not random but correlated with high demand conditions and correlated across wind units.

NYISO and ISO-NE calculate UCAP for intermittent resources based on an historical capacity factor adjusted to remove the effects of outages.[69] PJM calculates the UCAP for intermittent resources based on a historical capacity factor during summer peak hours (HE 15, 16, 17 and 18).[70] The PJM approach can to a degree capture the correlation between low output and hot, still summer conditions, but some of the hours included in the calculation of the capacity factor may be low load, windy conditions. It may be necessary to restrict the calculation of the capacity factor to the high load summer peak hours, rather than all peak hours, to accurately measure the contribution of wind units to meeting summer peaks. Once again, it is potentially difficult to account for the reliability impact of non-random outages in an ICAP system.

5. Discussion

The common feature of all of these energy limitations is that an ICAP system does not provide enough incentive for capacity to be available during peak conditions. This is intrinsic to the current ICAP systems. These ICAP systems necessarily pay the generator less for being available during the peak shortage hours than the generator would receive during shortage conditions under an energy only market with a price cap based on the value of lost load. ICAP systems attempt to compensate for this incentive problem by requiring that resources receiving compensation for providing ICAP demonstrate their capacity. This approach works well for many thermal resources as if the capacity is available, forced outages will be random and this random risk can be analyzed. This approach is not adequate, however, to deal with fuel availability limits and start-up conditions in particular, as resource availability under strained system conditions depends on choices made by the resource owner, and resource owners will not incur the efficient level of costs to maintain availability if they realize limited returns from incurring those costs.

On the other hand, energy market prices (for both energy and reserves) can provide appropriate incentives for dual fuel operation, keeping oil in storage, etc., and some of the problems experienced in Texas and NEPOOL may be transitional issues with new generation and new market conditions. Even absent modification of the NEPOOL ICAP system, we may see developers focusing on providing dual fuel capability. These complications in using an ICAP system to ensure that both energy and capacity are available during stressed system conditions are leading to further evolution of Eastern ICAP markets, but the evolution is proceeding in very different directions in PJM (RPM), ISO-NE (locational ICAP with stronger availability penalties) and NYISO (greater

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69 New England Power Pool, Market Rule 1, Section 8.3.6. NYISO Service Tariff Section 5.12.11(d), Sheets 142, 135B, 15B.01. NYISO is evaluating its methods for evaluating the ICAP availability of wind resources.

70 PJM Manual 21, Rules and Procedures for Determination of Generating Capability, Appendix B, April 30, 2004.

reliance on shortage pricing in the energy market) and it is not clear which if any of these approaches will prove to be workable and successful.

E. Retail Access

1. Overview

Under power pool operation, both PJM and New York had reserve requirements imposed on each of the transmission owner LSEs belonging to the pool. Each transmission owner had an obligation to serve load in its service territory so they were able to anticipate their reserve requirements and to add capacity to satisfy the annual requirements when needed to meet load growth. The potential for the exercise of market power by generation-long utilities was constrained by the ability of pool members to anticipate future reserve requirements and to add quick-start capacity or return mothballed units to operation to meet ICAP requirements within the planning horizon.

This system is fundamentally altered by retail access as LSEs under retail access systems do not know what load they will be serving on any future date and generally only have short-term contracts with their retail customers. Moreover, there is the potential for individual LSEs to satisfy their individual ICAP requirements by releasing customers if ICAP prices are high, dumping an ICAP requirement upon the provider of last resort. In an environment with retail choice, ICAP markets must incorporate mechanisms to accommodate load switching between LSEs without undermining the reliability role of the ICAP requirement. Critically, compatibility of ICAP systems with retail access requires a mechanism for settling day-to-day imbalances in ICAP positions as load shifts between LSEs.

The need for a daily balancing system in the ICAP market is a potential problem as suppliers do not take capacity out of service or put it in service on a day-by-day basis so prices in these daily ICAP imbalance “markets” may not reflect market forces. Suppose, for example, that LSE A contacts for 250 MW of ICAP with four different suppliers, paying $36,600/MW year for the ICAP, an average of $100/MW day. If LSE A loses 50MW of load to LSE B on June 1, what is the market value of this ICAP? On the supply side, what would the marginal ICAP seller pay to buy back the ICAP from LSE A so that the supplier could close its plant and avoid its going-forward costs for the rest of June? The likely answer is not much. The $36,600 in going-forward costs on an annual basis is not incurred on a daily basis, $100/MW day, but is incurred in chunks and once incurred is sunk. If the seller has already taken his unit off-line and incurred maintenance costs, how much will the seller save by mothballing the unit during June? By June, the marginal ICAP seller has probably already entered into a variety of contracts that it cannot cancel on a monthly basis. Even labor costs may be sunk to an extent, for if the generator lays off its employees in June, it may not be able to rehire them in July, so labor costs also may not be variable on a daily or even monthly basis.

Conversely, if LSE A refuses to sell the ICAP it no longer needs to LSE B, what is the supply price at which additional ICAP would enter? If the next highest cost ICAP supplier at the beginning of the year offered ICAP at $ 36,966/MW year ($101/MW day), this supply would very likely not be offered for the month of June for $3,030/MW. That marginal supplier might not be even able to bring its capacity out of mothballs soon enough to be available during June and, even if it did, it might need to incur nearly the same $36,966 to be available in June that it would have incurred in order to be available for the year.

The only significant supply-side factor affecting daily ICAP prices is the value of being able to sell power into higher priced external markets by withdrawing from the ICAP market and eliminating the associated recall right. Because supply in the ICAP market otherwise does not change in the same time frame in which retail access markets settle imbalances, the market price of capacity in a daily market, absent the exercise of market power, is likely to either be zero or rise to the level of the deficiency payment.

Moreover, if suppliers are able to withdraw from the ICAP market to avoid the recall obligation, daily imbalance pricing in the ICAP market can lead to supplier behavior that turns ICAP market prices into a mirror of energy market prices (eliminating the smoothing role)[71] and lead to LSE behavior that undermines the reliability function of the ICAP market. Under ICAP systems, LSEs that do not contract for sufficient generation to meet their ICAP requirement must pay a deficiency charge. If the price of ICAP is volatile and varies day-by-day based on the value of capacity in external markets and LSEs have the option of paying daily deficiency charges instead of buying ICAP, LSEs will have an incentive to buy ICAP when the daily price is less than the deficiency charge and to pay the deficiency charge when the ICAP price would be higher. This behavior can produce a shortage of ICAP during precisely the days on which it is needed as suppliers pull out of the ICAP market to avoid recall whenever the differential value of the capacity outside the ICAP system exceeds the deficiency price.

The potential problems that a daily balancing market for ICAP can give rise to are discussed in Section 2 below with reference to PJM. Section 3 then discusses how NYISO and ISO-NE have addressed the daily balancing problem.

2. Daily Balancing in PJM

In PJM, LSEs are not required to procure ICAP to cover the loads they serve until the day before the operating day. In addition, ICAP suppliers can pull their capacity in and out of

71 While one could design an ICAP market to have daily prices that are as volatile as those in an energy-only market, there is not much point to having an ICAP market if the volatility that would otherwise be present in the energy market is simply shifted into the ICAP market. NEPOOL initially had such a system in its operating capability market, which tended to track energy market conditions, and was eliminated after a relatively brief experience.

the PJM ICAP market (thus avoiding the recall obligation) on a day-to-day basis.[72] These market rules tended to drive the PJM ICAP market into a cycle in which the price was either zero or rose to the deficiency payment. On the one hand, the cost of keeping a unit available on a day-to-day basis is essentially zero because a supplier cannot mothball or activate units from day-to-day.[73] Thus, in the very short run the only cost of supplying ICAP is the revenue foregone by being unable to sell non-recallable energy into adjacent markets.[74] What this means is that the value of PJM ICAP is generally zero on a daily basis but occasionally spikes on those individual days when there is high demand for capacity both within and outside of PJM and the short-term value of ICAP closely parallels the value of energy in external energy markets.

Thus, over the 1,073 days from January 1, 1999 through March 31, 2004 the PJM UCAP payment averaged less than $1/MWday. In fact, the PJM UCAP payment averaged less than $1/MWday in 32 of 63 months in that period. The trend is even worse with the UCAP payment averaging less than $1/MWday in 25 of the 33 months since June 2001. Conversely, however, the daily clearing price exceeded $160/MW for 73

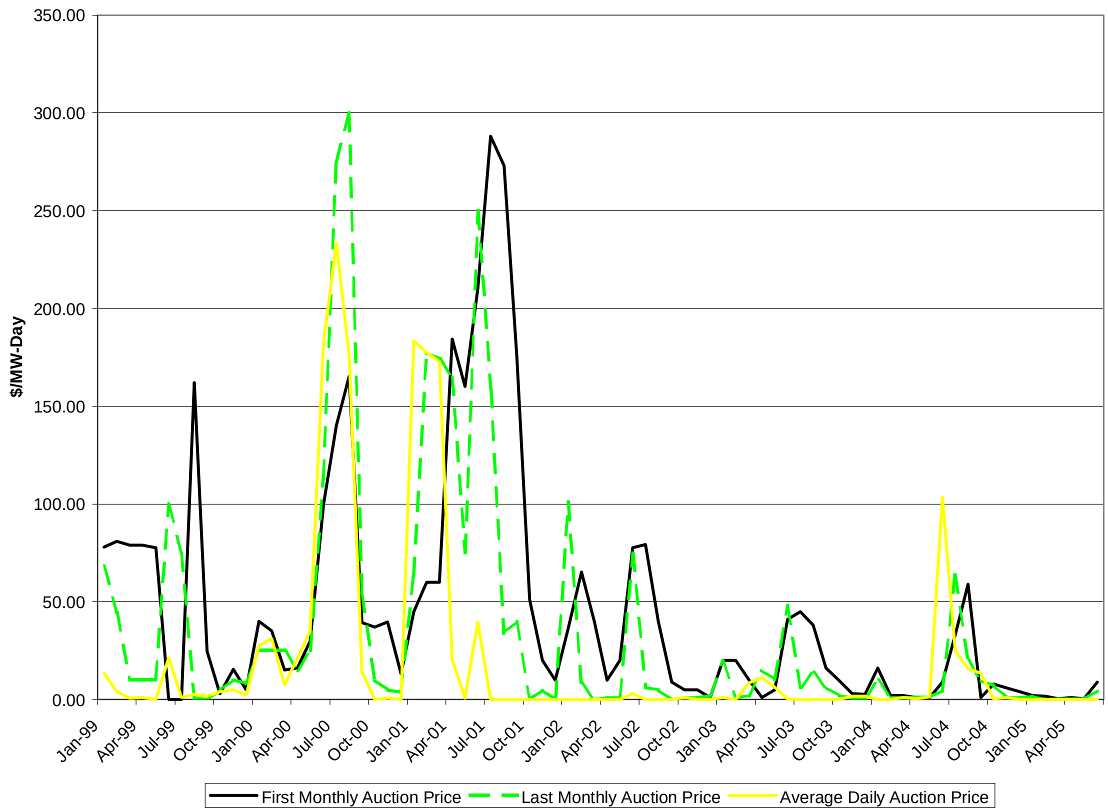
72 PJM Operating Agreement, Schedule 11, Section 6.

73 The costs referred to are the costs of having a unit available to be committed in the PJM day-ahead market, not the commitment costs themselves, which would be recovered either in energy prices or through the bid production cost guarantee.

74 In PJM, as in NYISO and ISO-NE, capacity that is committed to PJM as ICAP is permitted to sell energy out of PJM under ordinary conditions, but any exports purchased from the PJM spot market or sourced from PJM ICAP resources are subject to recall by PJM during shortage conditions, even if the price is much lower in PJM than in adjacent regions.

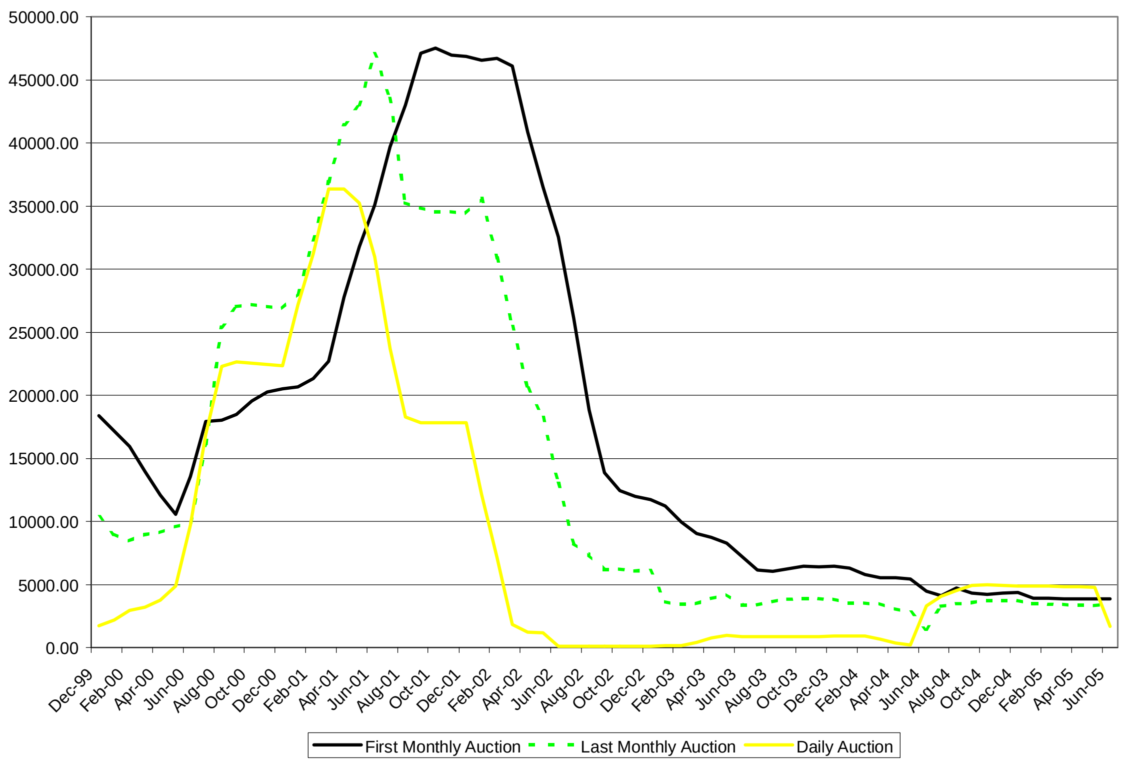
days over the June through August 2000 period and 85 days over the January through March 2001 period. PJM also runs various monthly and strip auctions with similarly volatile prices. Figure 13 portrays the volatility of PJM UCAP prices.

Figure 13
PJM UCAP Market Prices



Overall, the prices in the daily UCAP market have yielded a annual per MW UCAP payment of slightly more than $7,000 over the period January 1999 through June 2005, but only about $1,500/MW year since June 2001. The prices in the first monthly auction covering each month averaged $16,700/MW year over the period since January 1999 and about $12,000/MW year since June 2001. Similarly, the prices in the final auction for each month averaged a little over $17,000/MW year since January 1999 but only a little more than $5,000/MW year since June 2001 (see Figure 14 below and Table 22, appended). Overall, PJM ICAP prices have been very low since mid-2001.

Figure 14
PJM 12-Month Rolling Average UCAP Payment ($/MW Year)



While these are very low payments compared to the long-run cost of capacity, the low payments since June 2001 can perhaps be viewed as the logical outcome of a capacity glut (except that, as noted above, the capacity glut is limited to certain subregions).

One limitation of the initial PJM ICAP system that contributed to this outcome was that PJM calculated deficiency payments on a daily basis, prorating the annual deficiency charge over the number of days the LSE was short. Thus, with a annual deficiency charge of $58,400, this prorated to a charge of $160/day for a deficiency (on an ICAP basis, when applied to UCAP the deficiency charge was somewhat higher). If the going-forward cost of keeping capacity available in PJM worked out to $25,000/MW on an annual basis, this value might be recovered in two or three summer days when the value of capacity outside PJM ranged from $1000 to $15,000. An LSE could avoid these costs, however, by simply going short on those three days and paying the deficiency charge, but this left PJM short of capacity on the hottest days of the year when capacity was worth more outside PJM, leaving PJM unable to recall this capacity to maintain reliability.

PJM has attempted to address these incentive problems by developing rules that limit the ability of market participants to pay the daily deficiency charge to circumstances in which load shifts have resulted in the deficiency. Thus, effective July 1, 2001, if an LSE is short of ICAP due to a load shift, it is assessed the deficiency penalty, prorated on a daily basis. LSEs have from 10-40 days to cure such a deficiency before PJM deems it not to have resulted from a load shift. ICAP deficiencies not attributable to load shift are assessed the deficiency charge for the entire ICAP interval.[75]

3. New York/New England

In New York (and New England), each LSE is required to procure ICAP in advance of each month based upon the loads the LSE is expected to serve at the beginning of that month. The NYISO UCAP market consists of three auctions. The first is the capability period or strip auction which is conducted 30 or more days prior to the start of each six month capability period. The second is the monthly auction in which UCAP is bought and sold for each individual month remaining within the current capability period. The third auction was originally called the deficiency auction, and is called the spot market auction under the UCAP demand curve system.

There is no daily ICAP auction in New York or New England. Instead, New York and NEPOOL LSEs that lose loads during the month are credited for the value of the ICAP acquired to serve the loads they lost. The ISOs calculate an adjusted daily ICAP requirement for each market participant as customers are gained and lost.[76] The value of that ICAP is based upon the price paid in the ISO ICAP auction for that month, prorated for the part of the month in which the LSE did not serve that load. LSEs that gain loads are assessed a charge that is calculated in a similar manner. This avoids the indeterminancy of daily ICAP prices but ICAP prices are also likely to be indeterminate on a monthly basis, because capacity also does not enter or leave the market from month to month.

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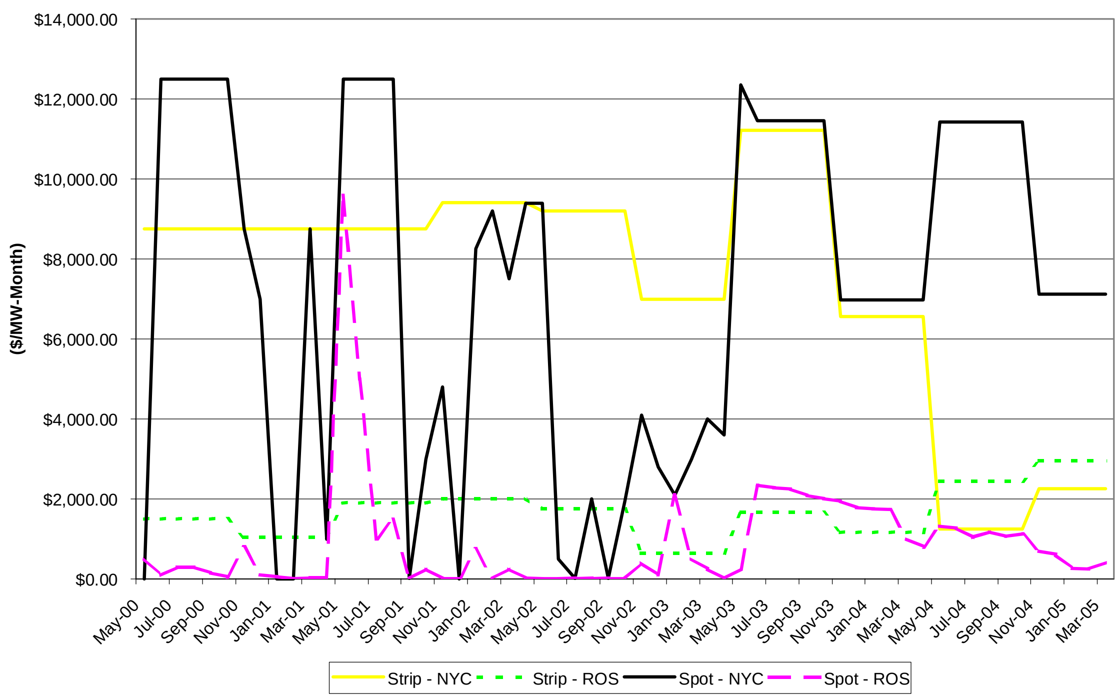
[75] Thus, if an LSE is deficient because it has gained load, it can pay the daily deficiency charge for a period of time. If an LSE becomes deficient because it did not buy enough ICAP during a period in which its load remained constant or declined, then it is assigned deficiency charges covering the entire ICAP interval. This amounts to requiring the deficient LSE to pay the deficiency charge for every day of the interval on the largest deficiency it incurs for reasons other than load shifts on any day of the interval. PJM Reliability Assurance Agreement, Schedule 11, Sheets 53-54; PJM Unforced Capacity Market Business Rules, p. 5.

[76] NEPOOL Installed Capacity Manual; NYISO Installed Capacity Manual, Section 3.5.

New York initially considered a deficient LSE to be deficient for a six-month period. At present, New York purchases capacity to cover the obligations of LSEs that have not nominated sufficient UCAP to cover their obligations for a month through a centrally conducted auction. LSEs can nominate resources to meet their share of the requirement, but if they do not do so, the ISO will buy UCAP for them for that month in this auction (and send them the bill). Figure 15 shows that locational strip auction UCAP prices in New York City have been relatively high, while rest-of-state UCAP prices have been relatively stable at around $22,000/MWyear.[77] The prices in the New York deficiency auction have been more variable and began in 2002-2003 to resemble the zero prices seen in PJM, despite the fact that New York does not have substantial excess capacity in its generation market.

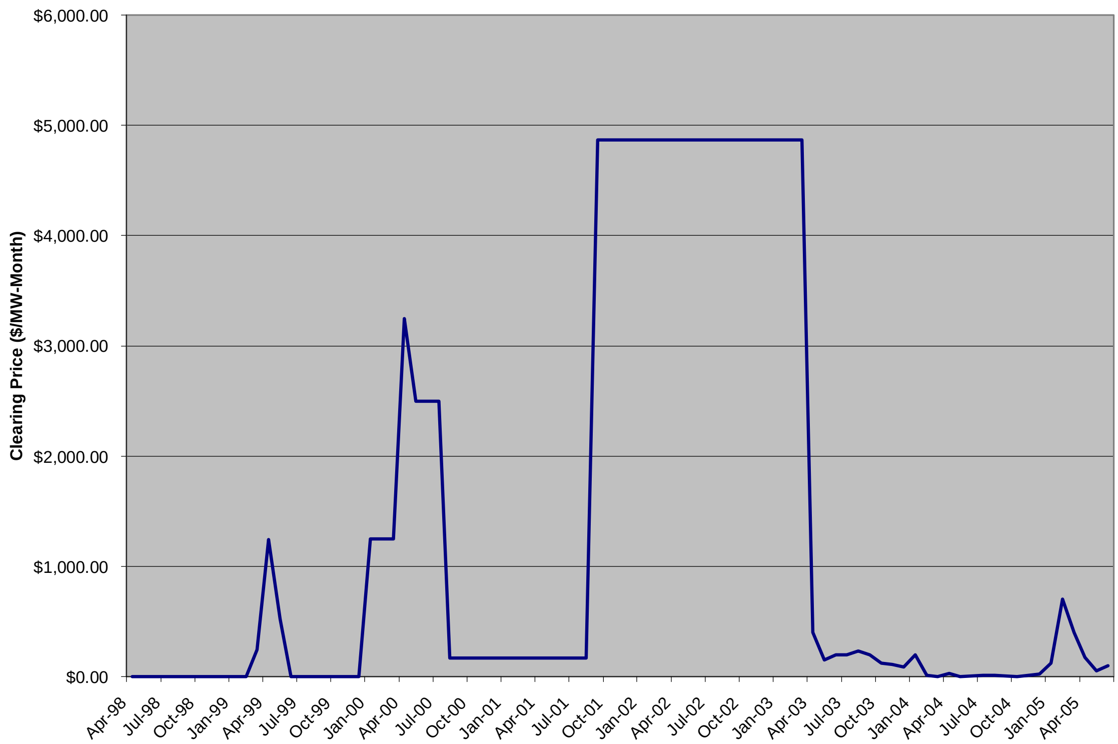
Figure 15
NY ICAP Strip Auction Results



[77] The prices tend to be lower in the winter because the NYISO calculates a single annual ICAP/UCAP requirement but uses summer ratings to determine summer supply and winter ratings to determine winter supply.

New England's ICAP market has worked poorly. Initially, both the ICAP requirement and ICAP prices were determined after the fact, making any kind of rational market behavior difficult to achieve. UCAP prices were generally zero through 1999, then rose substantially in the first seven months of 2000 (see Figure 16, below, and Table 21, appended).

Figure 16
NEPOOL Monthly ICAP Market Results



In early 2000, ISO-NE sought to terminate its ICAP market on the basis that it was subject to manipulation. This termination was approved by FERC and ISO-NE replaced the ICAP auction with a token deficiency charge and no ICAP auction. FERC did not approve this token deficiency charge and it was ultimately replaced with a $4,870 MW/month deficiency charge,[78] effective September 2001.

In April 2003, NEPOOL implemented an ICAP market modeled after New York's, but UCAP prices have been low, presumably reflecting the overall capacity surplus in New England.[79] New England's procedures were then similar to New York's system prior to implementation of the ICAP demand curve. The primary difference was

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78 It can be seen in Figure 16 that the FERC mandated ICAP charge was higher than the ICAP prices alleged to have been impacted by market manipulation.

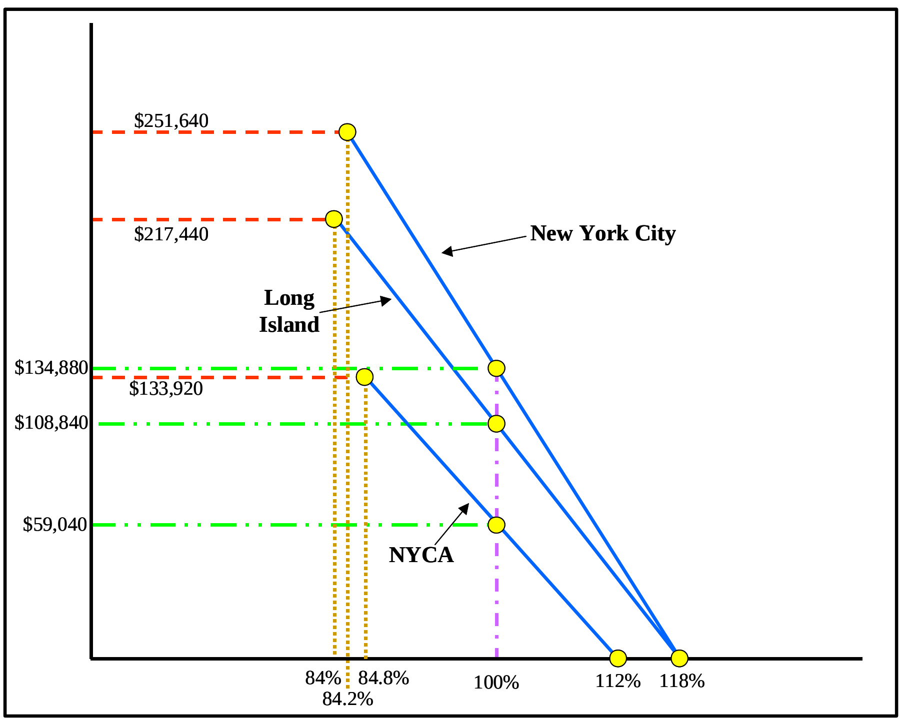
79 As in PJM, New England has an overall capacity surplus but does not have a surplus in all subregions.

in the way that the monthly auctions were conducted. ISO-NE simply offered to purchase the amount of ICAP needed to cover obligations of LSEs that had not nominated sufficient ICAP to cover their obligations. This amount was capped by the deficiency charge. In 2004, as noted above, ISO-NE filed to implement locational ICAP requirements and an ICAP demand curve modeled after the New York ICAP market.

4. *Demand Curve*

Beginning in 2003, the NYISO has defined a ICAP demand curve that is applied in the NYISO UCAP spot market auction. Instead of being fixed, the amount of UCAP purchased depends on the price of UCAP. A target price is set for the target level of UCAP, and if more than the target level of UCAP is offered at the target price, more UCAP is purchased and the UCAP price falls. Conversely, if less than the target level of UCAP is offered, the quantity purchased falls and the UCAP price rises, but the price rises along the demand curve rather than the market price rising to the level of the deficiency charge. The initial demand curves for UCAP in Summer 2003 are portrayed in Figure 17.[80] The target price figure for New York City, $127,890/MW ICAP year increased to $151,140 in 2004. Similarly, the initial Long Island ICAP target price escalated to $123,940 in 2004, while the NYCA target price escalated to $67,490. An independent study was to determine the ICAP target price for 2005.[81]

Figure 17
NYISO Summer 2003 UCAP Demand Curve



80 Arthur Desell, Installed Capacity (ICAP), The Reliability Market.

81 NYISO Installed Capacity Manual, pp. 5-6 to 5-7.

The Summer 2004 ICAP demand curves are portrayed in Figure 18 and were relatively similar to the 2003 ICAP demand curves.

Figure 18
NYISO Summer 2004 UCAP Demand Curve

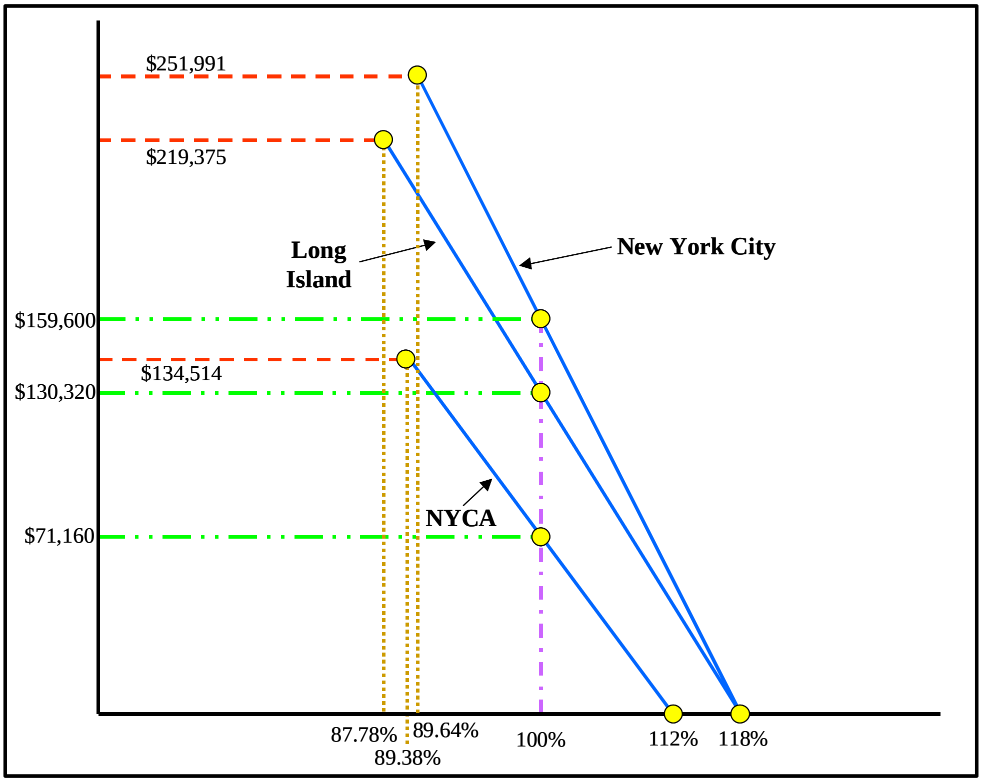
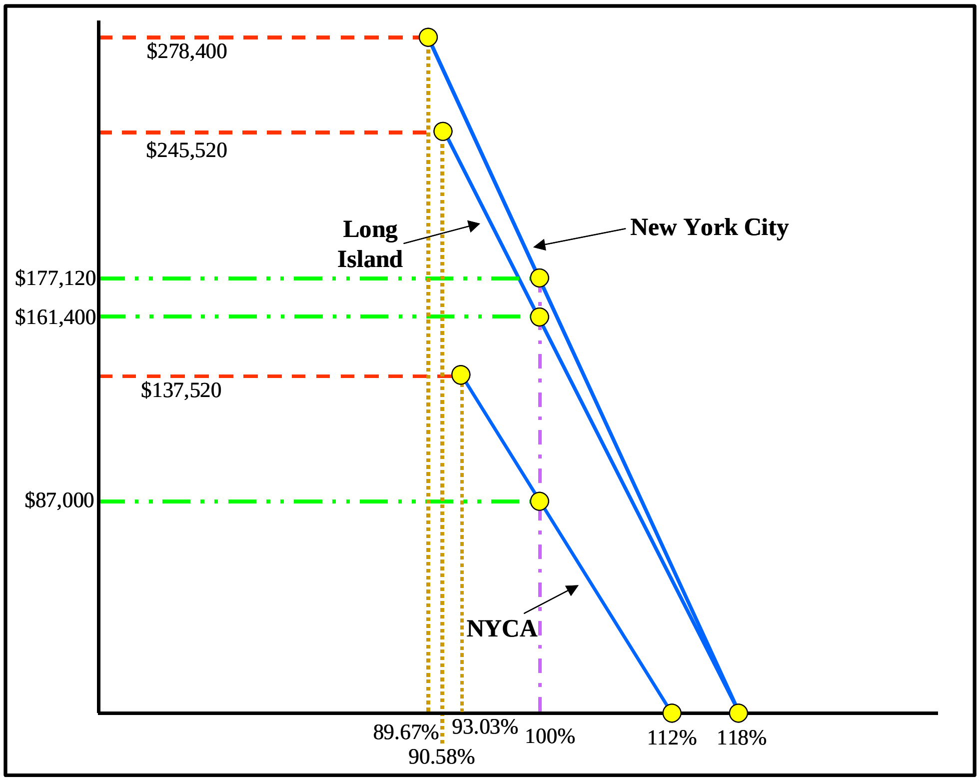


Figure 19 portrays the Summer 2005 ICAP demand curves. It can be seen that the target and maximum ICAP prices have increased further.

Figure 19
NYISO Summer 2005 UCAP Demand Curve



With implementation of the NYISO UCAP demand curve, the NYISO spot market auction replaced the NYISO deficiency allocation. The UCAP demand curve is applied in the UCAP spot market auction. Unforced capacity is offered into the UCAP spot market auction to determine both the quantity of unforced capacity purchased in the auction and the price. LSEs that have not purchased sufficient UCAP to cover their obligation become net purchasers, while LSEs with excess UCAP or resource suppliers are net sellers.[82]

The effect of the UCAP demand curve is to make the demand for UCAP somewhat elastic, which dramatically reduces the likelihood that a small capacity surplus will drive the UCAP price to zero or near zero. This auction structure both reflects the belief of the NYISO and NYPSC that incremental capacity has reliability value and a concern with eliminating the potential incentive of UCAP buyers to engage in strategies

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[82] See NYISO Services Tariff, Section 5.14. See also John Charlton, "NYISO Demand Curve as Proposed for the NYCA Installed Capacity Market," March 14, 2002.

that artificially depress the UCAP price.[83] The UCAP demand curve in New York appears to have stabilized UCAP prices in the spot market auction and ISO-NE included an ICAP demand curve in its proposal for a locational ICAP system.

The ISO-NE demand curve was originally targeted to recover the estimated cost of new capacity at 106.7 percent of the NEPOOL objective capability target, implying a reserve margin of roughly 18 percent over peak, similar to the margin in New York and consistent with the actual reserve margin maintained under NEPOOL operation. The ICAP demand curve would then slope down to a zero payment at 118 percent of objective capability or roughly 112 percent of the full recovery price.[84] The demand curve was to be capped at 95 percent of objective capability, or roughly 89 percent of the full return ICAP target.[85]

The UCAP demand curve system has limitations. First, the market price of ICAP is stabilized in part because the demand curve in effect chooses an administrative UCAP price, with the price rising or falling around this target to balance supply and demand. If the target price is too high, too much UCAP will be purchased at too high a price. While it is not necessary that the target price exactly correspond to the competitive price to achieve reasonable outcomes, material errors in setting the target price will produce ICAP shortfalls or excess ICAP purchases.

Second, the UCAP demand curve tends to undermine forward contracting for ICAP because LSEs that forward contract are not hedged for the cost of the additional UCAP above the target that clears in the spot market auction. This would be an important limitation if substantial long-term forward contracts for UCAP were being entered into but it is not clear that this is the case. It has been suggested that the demand curve has reduced long-term ICAP contracting in New York, but no data are publicly available. It appears that there has perhaps been a reduction in ICAP sales in the strip auctions since implementation of the ICAP demand curve.

5. Discussion

The underlying problem that retail access poses for ICAP systems is that most retail access systems are fundamentally inconsistent with long-term commitments, which undercuts reliance on the ICAP market to support entry and reliance on competitive entry to keep ICAP markets competitive. Unfortunately, retail access programs pose similar

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83 See Raj Addepalli, Harvey Arnott, Mark Reeder (New York PSC), Prepared Testimony Regarding a Proposal by the NYISO Concerning Electricity Capacity Pricing, March 6, 2003, pp. 3-5; New York PSC, Resource Demand Curve, January 31, 2003.

84 ISO-NE March 2004, pp. 19-21. Many changes were made in the ISO-NE proposal in August 2004 and in subsequent modifications of that proposal. This evolution is not covered in this paper.

85 ISO-NE March 2004, pp. 23-25

problems for energy only markets so the problem cannot be addressed by switching to reliance on energy-only markets to maintain reliability.

Residential customers are unlikely to be willing to sign long-term energy contracts that lock in payments for ICAP over a five to ten year period. Given the typical rate at which people change houses, residential customers signing 5- to 10-year power contracts could be faced with buying out uneconomic contracts or trying to capture the value of in the money contracts from the new owner or renter. For whatever reason, residential contract duration is generally one year or less, too short to support long-term ICAP or energy purchase contracts. Long-term contracts under retail access may pose fewer problems for commercial and industrial accounts.

Short-term sales contracts with residential consumers could nevertheless in principle support long-term fixed price ICAP or energy purchase contracts by LSEs. Oil companies, for example, have supported the construction of crude oil and refined product pipelines through long-term take-or-pay contracts with the pipeline, despite the fact that the refiners have no contract with retail motorists. While long-term fixed price ICAP or power purchase contracts would increase the risk of retail access providers, the riskiness of these contracts could be managed by periodically entering into long-term contracts for only a portion of the retailers customer demand. Several common features of retail access markets may render such a strategy unworkable in electricity markets, however.

Such a retailer would lose money when the market price of ICAP or power fell below its long-term contract price, but it would make money when the market price of ICAP or power rose above the long-term contract price. By entering into a temporally diversified set of power purchase contracts, such a retailer could limit its risk exposure to sudden swings in market prices.

There appear, however, to be three features of retail access markets that undercut long-term ICAP or energy contracts that are not hedged by long-term customer contracts. First, such long-term contracts would only be economic if the losses incurred when the market price of ICAP is below the contract price were offset by profits when the market price of ICAP is above the contract price. If the retailer were a regulated utility that cannot retain such a difference between the contract price and the market price, then the risk of loss with no offsetting possibility of gain would preclude entering into either long-term ICAP or energy contracts.

Second, unregulated LSEs may be unable to benefit from low contract prices during periods of high ICAP prices if the regulated price to beat does not rise commensurately. Retail rate regulation policies that tend to keep the price to beat too high when ICAP and energy prices are low and too low when ICAP and energy prices are high tend to discourage long-term ICAP and energy contracts. With such a retail price structure it is more profitable for unregulated LSEs to shed customers back to the utility when ICAP prices rise than to enter into long-term contracts that hedge ICAP costs.

Finally, the third factor is the risk of regulatory change. ICAP is an artificial product. LSEs may be deterred from entering into long-term ICAP contracts by the risk of regulatory changes. Particularly problematic would be regulatory change which retains the ICAP system, and thus does not trigger clauses terminating payments if the ICAP requirement is terminated, but dramatically reduce the price of ICAP. ISO NE's decision to dramatically reduce the ICAP deficiency payment without eliminating the requirement would be an example of this kind of risk.[86] Another example of regulatory risk is the introduction of locational ICAP in New England. A Boston LSE that had entered into a 10-year ICAP contract would find itself no longer fully hedged.

ICAP systems would be more workable in combination with retail access programs in which residential customer demand is covered with multi-year contracts as these contracts could provide the basis for multi-year ICAP contracts. Still, the interval between the signing of the contract and the duration of the contracts limits the ability of the LSE winning the retail contact to contract with new generation entrants to meet its ICAP obligations. Unless the generation entrant is very far along in the development/construction process, it would not be on line in time to hedge the load contract.

F. Capacity Imports

A further element of an ICAP system is the need to account for imports and exports. This has two aspects. First, a critical component of all Eastern ICAP systems is the right of recall for exports supported by ICAP capacity. In the NYISO, external transactions supported by ICAP resources are subject to real-time curtailment to resolve a NYISO reserves shortage.[87] In PJM, all exports supported by capacity resources may be interrupted to serve PJM load if PJM declares a maximum generation emergency.[88] Similarly, sales out of the New England control area from ICAP resources can be interrupted to serve New England load if ISO-New England declares an emergency condition.[89]

The second element of these rules is the treatment of capacity imports. Traditionally, the Eastern power pools assumed that a certain amount of power would be available on some interface under stressed conditions and netted this from the collective pool capacity requirement. To avoid double counting of the import power relied upon in this reliability analysis, PJM for example, imposed a CBM margin which made most of

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86 Of course, there is also the risk of tightened requirements and FERC in fact ultimately restored a substantial deficiency payment.

87 NYISO Services Tariff, Section 5.12.10.

88 PJM Operating Agreement, Schedule 1, Section 1.11.3A, June 22, 2005.

89 ISO New England, Market Rule 1, Section III.1.11.4, December 22, 2004.

the external transfer capability unavailable to support firm imports.[90] With the development of explicit recall rules, this logic is less compelling as external ICAP must be dedicated non-recallable capacity.

The NYISO places an overall limitation on the amount of the ICAP requirement that can be met with external resources (2,755 MW) and then places additional interface by interface limits on external resource ICAP imports.[91]

ISO New England also makes the transfer capability of each interface, net of grand fathered agreements and less any tie line benefits assumed in calculating the ICAP requirements, available to support ICAP imports.[92]

One problem that has manifested itself with respect to ICAP imports is the need for more detailed security analysis of import capability, as in some cases transmission maintenance outages can dramatically reduce transfer capability and render ICAP undeliverable. Thus, it is probably not appropriate to make the entire N-1 transfer capability on an external interface available to support ICAP imports, as a single maintenance outage could make much of this ICAP unavailable. There may therefore be a movement toward using N-2 transfer capability to define limits for external ICAP.

A second and rather contentious issue is the treatment of units seeking to split their capacity between pools. The ISO-NE rules permit potential ICAP suppliers to delist their resources as qualified NEPOOL ICAP resources prior to the start of the obligation month effective at the beginning of the month.[93] An important and controversial element of the ISO-NE ICAP rules is that only whole resources may be delisted.[94] One reason for such a rule is to facilitate monitoring of compliance with outage and derating rules, which are potentially subject to circumvention if the market participate can choose how to assign outages between multiple ICAP markets. Split ICAP units also complicate market power mitigation and enforcement of the DAM bidding requirement, as software needs to account for distinct physical unit upper limits and ICAP upper limits.

A third issue relating to imports is methodology for assessing the amount of imported energy that will be available under stressed system conditions. This is

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90 The PJM CBM margin was quite different from CBM margins used in the Midwest. The PJM CBM margin only reserved the sale of this capacity as firm transmission service, thus making it unavailable to support firm imports for ICAP. In real-time all of the transfer capability was made available for use to support non-firm transmission. The PJM CBM margin was simply a mechanism for managing reserve requirements. There was no need to restrict use of CBM capacity to support imports in real-time as these imports met PJM load just as well as emergency imports. See PJM OATT, Attachment C, Sheet 280.

91 NYISO Installed Capacity Manual, Section 2.7, and Attachment B.

92 NEPOOL Manual for ICAP, Attachment G, Section 1.5.

93 ISO-NE Market Rule 1, Section 8.3.4, Sheet 86; NEPOOL ICAP Manual, Section_3.9.1.

94 ISO-NE Market Rule 1, Section 8.3.4

addressed by including external adjacent regions in the Monte Carlo analyses used to develop the ICAP requirement. The reliability analysis therefore models transmission constraints in the external regions and accounts for the potential for correlations in weather conditions that will limit the ability to rely on external supplies. For example, the New York State Reliability Council models the outside world by matching their three highest peak load days to the corresponding NYISO load levels.[95] PJM's determination of its reserve margin includes modeling of the rest of the world, including NPCC, SERC and ECAR.[96]

G. Market Power

Although resource adequacy is often tied to market power mitigation, the implementation of ICAP systems does not mitigate the exercise of locational market power. If a resource owner has locational market power in energy markets, then it will also have market power in ICAP markets. The ability of LSEs to enter into long-term contracts with generation entrants at competitive prices will often preclude or constrain the exercise of market power in long-term ICAP markets, but entry provides the same competitive pressure in long-term energy markets. Conversely, any potential for the exercise of locational market power that exists in spot energy markets would generally also exist in short-term ICAP markets.

The most important difference between ICAP and energy markets from the standpoint of market power is that economic withholding becomes progressively more difficult to identify as the timeframe moves further away from real time. In a centrally dispatched system such as in PJM and New York, generation that is available (taking account of ramp constraints, deratings and environmental limits) and not generating energy or providing reserves in real time despite market prices that exceed its incremental /opportunity costs is economically withheld. While the application of this criterion can be complex for units managing energy or fuel limits and during periods of volatile gas prices, it is generally possible to clearly identify substantial economic withholding. When one moves to the day-ahead timeframe, economic withholding is somewhat less clear cut as a competitive seller would not offer to sell power in the day-ahead market for less than the expected real-time price, regardless of its incremental costs, and the expected real-time price is not observable. Market participants expecting high real-time prices, however, can use virtual load bids to arbitrage any difference between day-ahead and expected real-time prices while making all of their capacity available for commitment in the day-ahead market and for dispatch in real time.

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95 NYSRC 2004, p. 35.

96 PJM Manual 20, p. 19.

In ICAP markets, it is harder to define economic and physical withholding. In an ICAP market, the long-run floor on ICAP prices is provided by the avoidable costs of a unit that would not be recovered in energy and reserve margins. The avoidable costs of a unit can be roughly estimated based on historic costs as can past energy and reserve margins, but these past margins are not necessarily a good measure of current expectations. The shorter the timeframe the ICAP payments applies to, the harder it can be to distinguish economic or physical withholding from an unwillingness to keep money-losing capacity available. An ICAP owner might keep a losing unit available for a period of days despite zero daily ICAP prices but it would not agree to a forward commitment to keep the unit available for a sustained period of time as an ICAP resource for a zero ICAP price.[97]

The PJM market monitor concluded that the high ICAP prices in early 2001 arose from an exercise of market power and the rules regarding the allocation of deficiency charges were changed to modify withholding incentives.[98] It is noteworthy that the market monitor's analysis focused on comparing the value of the ICAP recall right to the price of ICAP, concluding that the offer prices in the daily ICAP market were well above the value of the recall right.[99] This conclusion illustrates the difficulty with market power analysis of ICAP markets. While the value of the recall right should place a floor under ICAP prices, it is not a ceiling. Energy prices could move in sync throughout the region producing zero differentials, yet generating capacity could require a capacity payment to remain in operation and provide ICAP. This is one of the disconnects between the daily pricing of ICAP and the term character of capacity decisions that complicates market power analysis as well as the effective functioning of ICAP markets.

IV. NORTHEAST RAM PROCESS

PJM, NYISO and ISO-NE formed the Interregional Resource Adequacy Model Group (RAM group) to develop a coordinated approach to ICAP for the Northeast. The resulting RAM group model called for centralized purchases by ISO, rather than by LSEs.[100]

The basic elements of the Central Resource Adequacy Model (CRAM) model were:

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[97] As noted above, the ICAP price is also bounded by the price at which the units ICAP capability could be sold for in adjacent regions or the value of being able to sell non-recallable power into adjacent regions.

[98] PJM initially allocated deficiency revenues to holders of unsold capacity resources. Thus, capacity that was withheld from the market received the deficiency payments. This rule was modified effective June 1, 2001. See PJM Market Monitoring Unit, PJM Interconnection State of the Market Report 2001, pp. 69-70, 79-94 (hereafter PJM 2001).

[99] PJM 2001, pp. 84-85.

[100] Joint Capacity Adequacy Group, Areas of Agreement and Areas Under Development, March 14, 2003 (hereafter JACG).

- Each ISO forecasts load and establishes an unforced capacity obligation for future operating years.

- Resources are committed to meet the unforced capacity obligation up to several years prior to the operating year.

- Each ISO coordinates its own separate centralized auction with coordinated timing.

- Auction participation (by sellers) is voluntary.

- Products that can be sold in the auctions include existing generation, planned generation, bilateral contracts for capacity resources, load management products and transmission upgrades.

- Bilateral contracts can be used by LSEs to self-provide their own generation.

- The centralized auction price of UCAP would be charged to all LSEs during the operating year.

- Resource providers would receive the market clearing UCAP price for their UCAP during the operating year.

- Periodic reconfiguration auctions to allow resource providers to cover changes in capacity positions, due to outages, unit cancellations, etc., but these later auctions would not change the price of UCAP for load, they would only price imbalances among suppliers.[101]

NERA studied five issues relating to the CRAM model:

- Planning horizon (how far should the auction precede supply commitment?).

- Commitment period (length of supply contract awarded in the auction).

- Auction format (descending clock, reverse English, pay as bid).

- Proportion of ICAP acquired in each auction

- Deficiency charges and bid caps.[102]

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[101] JACG; and Eugene Mechan, Chantale LaCasse, Philip Kalmus and Bernard Neenan, “Central Resource Adequacy Markets,” Final Report, February 2003, (hereafter NERA), pp. 8-9.

[102] Joint Capacity Adequacy Group, Areas of Agreement and Areas Under Development, March 14, 2003. NERA, p. 10.

Planning Horizon

The planning horizon issue addresses the question of by how long the UCAP auction should precede the date of the supply commitment. The longer the length of the planning horizon the more long-lead time resources can be offered in the UCAP auction. Conversely, if the planning horizon is too long, all resource projects other than existing generation will be so speculative that LSEs may be hesitant to commit to them and suppliers may be reluctant to commit to supply UCAP based on projects that are very early planning stages. Longer planning horizons would give rise to greater load forecast uncertainty that could increase UCAP requirements. It was also perceived that longer planing horizons would tend to exclude DSM programs from the ICAP auctions because consumers could not commit to demand-response programs that far in advance of the operating year.

The NERA Report proposed a minimum planning horizon of three years to allow entrants to compete effectively in the ICAP market. If the planning horizon were too short, capacity able to come on line in time to meet ICAP requirements would have to be so far along in the development/construction/financing process that the ICAP supply could not respond to UCAP prices. A short planning horizon would therefore tend to produce auction prices that were either zero or equal to the price cap, perpetuating current problems. NERA believed that it was desirable for the planning horizon to be long enough that development projects offered in the UCAP auction could go forward or not depending on the price in the UCAP auction.[103] NERA believed that a planning horizon satisfying this criterion would tend to stabilize UCAP prices around the long-run cost of generating capacity.

One potential problem with longer planning horizons is that since projects offered in the auction would necessarily be at an earlier stage in the development process than would be the case with a shorter horizon, there would be a greater potential for the projects to turn out to be uneconomic or infeasible for reasons not known at the time of the ICAP auction. This possibility would give rise to non-performance risk for the ISO running the auction as developers could submit speculative offers, anticipating that they would cancel the project if fuel costs or market prices moved in an unfavorable direction.

This kind of non-performance risk could be addressed by requiring that winning bidders post some kind of security, but such a security requirement could deter participation in the auction if the planning horizon is too long and the auction occurs too early in the development process for most projects. Indeed, these kinds of credit issues were a market participant concern with the CRAM proposal. NERA proposed to limit non-performance risk by restricting participation in the auction to projects in an advanced

[103] NERA, p. 13, 15—22.

stage of development, siting and permitting,[104] but this view did not accord with the perspective of other ICAP supporters.

In considering these risks, it needs to be kept in mind that under the current ICAP systems the UCAP requirements are only enforced a month in advance, so the possibility of projects being cancelled or delayed by environmental or other factors under the CRAM system between the time of the initial auction and the operating month does not create any new reliability risk relative to current ICAP markets. Moreover, although the NERA study did not propose this, defaulting capacity could be replaced in the reconfiguration auction.

NERA concluded that the three-year planning horizon appeared to be inconsistent with the participation of demand response resources and proposed carving out a portion of the ICAP market to be served in a shorter term auction for demand response resources.[105] This proposed approach was not popular with market participants because of the likelihood that this would in effect create separate ICAP markets and increase price volatility in the portion of the ICAP market served by demand response. An alternative approach would be to allow resources that did not sell ICAP in the three year forward auction to participate in the reconfiguration auctions and to allow offers in the three year auction that were not backed by explicit ICAP or demand resources but reflected an expected ability to develop such resources. The non-performance credit cost issue associated with such offers could perhaps be addressed be requiring stringent credit requirements only for UCAP offers not backed by projects or for projects in a very early stage of development.

Commitment Period

The commitment period issue concerns the duration of the ICAP contracts awarded in the auction. Longer contract durations reduce the risk for the seller and lower the price of ICAP but entail a longer financial commitment by the ISO.[106]

NERA recommended contracts with a duration of three years due to their assessment of the limits of centralized auction and customers. NERA proposed to implement this three-year commitment period by running annual auctions covering one-third of the ICAP requirement purchasing three-year ICAP requirements. Thus, in 2005 the ISO would purchase one-third of the ICAP requirement for 2009, 2010 and 2011; in 2006 the ISO would purchase one-third of the ICAP requirement for 2010, 2011 and

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[104] NERA, p. 21.

[105] NERA, pp. 31-32, 141-142.

[106] NERA, pp. 22-25, 28.

2012; in 2007 the ISO would purchase one-third of the ICAP requirement for 2011, 2012 and 2013, etc.[107]

A three-year contract duration provides a desirable improvement over the current monthly duration or capability period duration of ICAP contracts in the centralized auctions. Nevertheless, a three-year contract may not provide a sound basis to support the construction of new capacity and thus may have little practical impact on resource development.

An important feature of the CRAM proposal is that it can be bypassed by LSEs desiring to enter into longer-term customized contracts with resource suppliers. Such LSEs could sign 20-year contracts covering ICAP as well as energy and offer one-third of the ICAP they procure into each auction, hedging themselves against the ICAP charges. Thus, the three-year contract term in the centralized auction does not preclude longer-term bilateral contracts. As noted above, however, LSEs may not have an incentive to enter into such long-term contracts in states with shorter-term retail access programs.

The CRAM proposal in effect serves mainly to ensure that someone (the ISO on behalf of future loads) contracts for ICAP to cover the portion of load that may migrate from LSE to LSE and thus would not likely be hedged under long-term bilateral contracts. Moreover, the ICAP costs of serving this load will be known well in advance, enabling these costs of be recovered in retail contracts.

Single Auction or Tranches

One alternative would be to acquire the entire ICAP requirement for a given year in a single auction. This was perceived to have the advantage of yielding a single price. Another alternative would be to stagger the acquisition of ICAP, for example acquiring one-third of the requirement one year, one-third the next and one-third the next. NERA recommended a staggered approach as better minimizing market power problems and accommodating the auction of multi-year ICAP streams.[108]

Auction Format

NERA proposed a Descending Clock Auction. NERA viewed such an auction format as good for inter ISO procurement and for taking account of imports.[109]

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[107] NERA, pp. 13, 22-25.

[108] NERA, pp. 37-58.

[109] NERA, p. 13.

Deficiency Charge and Bid Cap

The issues were whether there ought to be a bid cap in the auction and how the deficiency charge, for suppliers that failed to perform, should be set.

NERA recommended a liquidated damages approach to setting deficiency payments, perhaps higher in the winter than the summer. NERA recommended that deficiency charges be assessed and come due at the time a UCAP provider's failure to perform is known, suggesting that missing a construction milestone and abandoning construction shortly after winning the auction would trigger the charge. The same penalty would apply if a unit's UCAP rating fell below the level sold in the auction.[110] This mechanism was tied in NERA's proposal to qualification criteria limiting participation to units in an acceptable stage of development and tied to a specific physically verifiable plant at a specific location (i.e., no virtual ICAP supply bids).[111] The triggers proposed by NERA do not appear consistent with permitting UCAP sellers to cover shortfalls by purchasing power in the reconfiguration auctions as envisioned by the original CRAM proposal.

Some market participants and regulators envisioned the CRAM proposal as permitting virtual supply offers.

Other Issues

The proposed three-year auction structure raises a variety of market power mitigation issues, some of which are discussed in the NERA report.[112]

Another important limitation of the NERA/CRAM proposal, particularly from the standpoint of NYISO market participants, was that it did not include an ICAP demand curve. This appears to have been a major stumbling block with Northeast market participants (and regulators). The ICAP demand curve has been to be relatively popular with NYISO market participants, many of whom believe the ICAP demand curve in New York is working much better than any of the other ICAP mechanisms and are reluctant to abandon it for an untried design.

NERA took the view that an ICAP demand curve was compatible with the proposed CRAM auction structure.[113] NERA criticized the concept of an ICAP demand curve on a number of grounds, some of which are consistent with the comments above.[114]

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110 NERA, p. 83.

111 NERA, p. 84.

112 NERA, Section 7.

113 NERA, pp. 119-126

114 NERA, p. 130-136.

As discussed above, an ICAP demand curve appears to have important potential limitations, but most have yet to manifest themselves. The CRAM approach would avoid the outcome of meaningless UCAP auction prices if generation projects would go forward or not based on the price of UCAP over a three-year term, as low prices would back out investment until prices rose and high prices would draw in investment. If a three-year contract term is not meaningful for project financing, however, then the CRAM proposal will not end the cycle of UCAP auction prices that are either zero or equal to the deficiency payment.

The CRAM proposal has a few other potential implementation issues or limitations:

- With a three-year planning horizon, how will load forecast errors that result in an ICAP shortfall be addressed?

- What happens if the ISO qualification process excludes resources that have already entered into bilateral ICAP contracts?

- How will simultaneous but separate ICAP auctions be coordinated?

The key feature of the CRAM proposal is that it is intended to address a very limited set of issues. It does not address the issues relating to deliverability requirements, outage incentives, or unit availability that were discussed above.

V. CONCLUSIONS

ICAP requirements can potentially provide a short-run incentive to keep some extra marginal generation in operation. In the long run, however, ICAP systems have several limitations that are related to their hypothetical structure.

- *Deliverability Tests*: Because ICAP providers are paid whether they run or not, ICAP markets need rules to provide locational incentives.

- *Availability Standards*: Because ICAP providers are paid whether they run or not, standards are required for availability levels and timing.

- *Conservation Incentives*: ICAP requirements keep extra capacity in operation. As a result, energy prices do not reflect the full cost of capacity.

- *Market Power:* The potential for the exercise of market power in long-run ICAP markets is constrained by entry. Entry and exit, however, do not constrain daily ICAP prices and retail competition leads to daily changes in ICAP requirements.

While these complications can be addressed with rules such as deliverability or locational ICAP requirements, UCAP systems, and demand response ICAP, none of these rules provide fully efficient incentives. One compromise may be to rely on a mix of high energy prices during shortage conditions (but not high enough to eliminate the operating cost shortfalls) and supplementary locational ICAP payments. If ICAP suppliers are dependent on energy market revenues for recovery of 25 to 50 percent of their net operating cost shortfall, they will tend to make more efficient decisions regarding dual fuel capability, ramping ability, manning levels and starting times, fuel storage, location, and recovery from outages.

While the multi-year structure of the CRAM proposal is attractive, it is not clear that a three-year contract would actually drive capacity investment, while the three-year planning horizon creates a number of difficulties. The fundamental problem in the Northeast are the incentives created by retail access programs or, more precisely, the lack of incentive for LSEs to enter into either long-term ICAP or energy contracts. If LSEs have the incentive to enter into long-term contracts for capacity (including constructing capacity), the NYISO demand curve approach is less attractive because it somewhat undermines these forward hedges, requiring supplementary capacity purchases by LSEs that entered into forward hedges. A variation on the NYISO demand curve system would be to allow LSEs to submit UCAP contracts prior to the spot market auction and to subtract these contracts from the UCAP requirement. Only the load of LSEs that were short would be represented in the spot market auction and they would be subject to the demand curve. Such a structure would somewhat stabilize short-term UCAP prices while not interfering with long-term contracts. The level of participation in the short-term auction might be very low, however, in which case prices might be volatile despite the demand curve.

APPENDED TABLES

Table 20
Average Daily Natural Gas Delivered to Consumers by Region (Excluding Vehicle Fuel) (MMcfd)

	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
1997-1998									
CA	5,003	5,043	5,449	4,422	4,860	6,085	6,538	6,776	4,897
WA-OR	682	877	960	904	1,352	1,625	1,544	1,676	1,518
AZ-NV-NM	938	982	941	759	863	1,324	1,448	1,278	1,187
Total	6,622	6,903	7,349	6,085	7,074	9,033	9,529	9,730	7,602
1998-1999									
CA	4,759	5,315	5,415	4,900	5,153	6,200	6,912	7,142	5,613
WA-OR	927	1,119	1,127	982	1,383	1,536	1,714	1,617	1,388
AZ-NV-NM	1,108	1,153	968	934	1,046	1,490	1,467	1,372	1,184
Total	6,794	7,588	7,511	6,816	7,582	9,226	10,093	10,131	8,185
1999-2000									
CA	5,154	5,390	5,513	5,827	5,322	5,967	6,348	6,334	5,902
WA-OR	793	855	977	1,361	1,408	1,696	1,795	1,738	1,508
AZ-NV-NM	1,005	1,037	959	1,006	1,035	1,493	1,493	1,409	1,261
Total	6,952	7,281	7,448	8,195	7,765	9,156	9,637	9,481	8,671
2000-2001									
CA	6,031	6,817	6,184	6,250	6,658	6,896	7,860	7,713	6,494
WA-OR	1,058	1,103	1,154	1,256	1,449	1,638	1,762	2,130	1,708
AZ-NV-NM	1,270	1,461	1,289	1,230	1,494	1,776	1,741	2,010	1,635
Total	8,360	9,381	8,627	8,737	9,601	10,310	11,362	11,853	9,837

Note: EIA defines natural gas delivered to consumers as total consumption less lease and plant fuel and pipeline fuel.
Source: Direct Testimony of William W. Hogan Tables 46, 49 and 50.

Table 21
ISO-NE ICAP/UCAP Prices

Month	Clearing Price ($/MW-Month)
Apr-98	$0.00
May-98	$0.00
Jun-98	$0.00
Jul-98	$0.00
Aug-98	$0.00
Sep-98	$0.00
Oct-98	$0.00
Nov-98	$0.00
Dec-98	$0.00
Jan-99	$0.00
Feb-99	$0.00
Mar-99	$246.00
Apr-99	$1,243.00
May-99	$523.00
Jun-99	$0.00
Jul-99	$0.00
Aug-99	$0.00
Sep-99	$0.00
Oct-99	$0.00
Nov-99	$0.00
Dec-99	$0.00
Jan-00	$1,250.00
Feb-00	$1,250.00
Mar-00	$1,250.00
Apr-00	$3,248.00
May-00	$2,500.00
Jun-00	$2,500.00
Jul-00	$2,500.00
Aug-00	$170.00
Sep-00	$170.00
Oct-00	$170.00
Nov-00	$170.00
Dec-00	$170.00
Jan-01	$170.00
Feb-01	$170.00
Mar-01	$170.00
Apr-01	$170.00
May-01	$170.00
Jun-01	$170.00
Jul-01	$170.00
Aug-01	$170.00
Sep-01	$4,870.00
Oct-01	$4,870.00
Nov-01	$4,870.00

Month	Clearing Price ($/MW-Month)
Dec-01	$4,870.00
Jan-02	$4,870.00
Feb-02	$4,870.00
Mar-02	$4,870.00
Apr-02	$4,870.00
May-02	$4,870.00
Jun-02	$4,870.00
Jul-02	$4,870.00
Aug-02	$4,870.00
Sep-02	$4,870.00
Oct-02	$4,870.00
Nov-02	$4,870.00
Dec-02	$4,870.00
Jan-03	$4,870.00
Feb-03	$4,870.00
Mar-03	$4,870.00
Apr-03	$400.00
May-03	$150.00
Jun-03	$200.00
Jul-03	$200.00
Aug-03	$230.00
Sep-03	$195.00
Oct-03	$120.00
Nov-03	$111.00
Dec-03	$87.00
Jan-04	$200.00
Feb-04	$10.00
Mar-04	$2.00
Apr-04	$30.00
May-04	$0.01
Jun-04	$6.00
Jul-04	$9.00
Aug-04	$10.00
Sep-04	$6.00
Oct-04	$0.02
Nov-04	$12.00
Dec-04	$25.00
Jan-05	$120.00
Feb-05	$700.00
Mar-05	$400.00
Apr-05	$175.00
May-05	$50.00
Jun-05	$100.00

Sources: NEPOOL Installed Capability Market Report (April 1998-March 2003), available at:
http://www.iso-ne.com/settlement-resettlement/Pre-SMD_ICAP/Pre-SMD_Interim_ICAP/NEPOOL_Installed_Capability_Market_report.xls
Sources: NEPOOL Installed Capability Market Report (April 2003-Joly 2005), available at:
http://www.iso-ne.com/markets/othrmkts_data/inst_cap/icap/NewEngland_ICAP_Auction_Report.xls

Table 22
PJM 12-Month Rolling Average UCAP Payment ($/Year)

Month	12-Month Rolling Average Annual ICAP Payment: Daily Auction ($/Year)	12-Month Rolling Average Annual ICAP Payment: First Monthly Auction ($/Year)	12-Month Rolling Average Annual ICAP Payment: Last Monthly Auction ($/Year)
Dec-99	1,740.38	18,367.87	10,356.92
Jan-00	2,178.69	17,190.80	9,008.42
Feb-00	2,968.92	15,939.48	8,487.42
Mar-00	3,188.48	13,958.89	8,952.42
Apr-00	3,796.12	12,070.39	9,102.42
May-00	4,877.77	10,589.83	9,567.42
Jun-00	9,721.21	13,589.83	9,958.92
Jul-00	16,924.05	17,929.83	16,158.92
Aug-00	22,288.50	18,030.58	25,431.33
Sep-00	22,660.27	18,478.78	27,051.33
Oct-00	22,540.07	19,533.09	27,204.16
Nov-00	22,416.51	20,254.29	27,051.46
Dec-00	22,341.90	20,502.29	26,906.07
Jan-01	27,167.64	20,657.29	28,084.07
Feb-01	31,229.04	21,322.29	32,323.47
Mar-01	36,347.17	22,715.74	36,955.80
Apr-01	36,324.19	27,768.34	41,455.50
May-01	35,257.36	31,806.40	43,005.50
Jun-01	30,959.48	35,106.40	47,115.50
Jul-01	23,719.76	39,694.40	43,519.50
Aug-01	18,269.41	43,034.65	35,272.88
Sep-01	17,849.66	47,102.05	34,852.88
Oct-01	17,842.37	47,536.05	34,545.05
Nov-01	17,821.36	46,951.05	34,547.75
Dec-01	17,820.61	46,858.05	34,431.81
Jan-02	12,139.38	46,579.05	35,609.81
Feb-02	7,174.98	46,719.05	30,890.69
Mar-02	1,823.28	46,100.60	25,483.36
Apr-02	1,213.60	40,868.00	20,563.66
May-02	1,194.73	36,527.69	18,269.66
Jun-02	102.82	32,550.89	13,019.66
Jul-02	103.86	26,085.53	8,276.66
Aug-02	105.27	18,862.53	7,378.28
Sep-02	101.27	13,881.63	6,178.28
Oct-02	130.27	12,454.39	6,209.28
Nov-02	131.73	11,996.89	6,089.28
Dec-02	133.28	11,717.89	6,143.53

Table 22 (continued)
PJM 12-Month Rolling Average UCAP Payment ($/Year)

Month	12-Month Rolling Average Annual ICAP Payment: Daily Auction ($/Year)	12-Month Rolling Average Annual ICAP Payment: First Monthly Auction ($/Year)	12-Month Rolling Average Annual ICAP Payment: Last Monthly Auction ($/Year)
Jan-03	164.82	11,221.89	3,632.53
Feb-03	165.68	9,959.93	3,415.25
Mar-03	428.42	9,029.93	3,476.94
Apr-03	767.96	8,760.23	3,896.94
May-03	957.14	8,295.54	4,191.44
Jun-03	880.23	7,202.34	3,381.44
Jul-03	882.64	6,134.70	3,381.44
Aug-03	882.67	6,072.70	3,660.44
Sep-03	881.75	6,283.60	3,840.44
Oct-03	854.08	6,439.84	3,871.44
Nov-03	899.29	6,387.34	3,871.44
Dec-03	947.38	6,433.84	3,832.69
Jan-04	917.14	6,309.84	3,522.69
Feb-04	919.06	5,809.80	3,523.69
Mar-04	686.26	5,561.80	3,493.00
Apr-04	356.10	5,561.50	3,080.50
May-04	204.76	5,437.19	2,793.75
Jun-04	3,295.64	4,477.19	1,488.75
Jul-04	4,063.69	4,105.19	3,279.00
Aug-04	4,549.50	4,756.19	3,465.00
Sep-04	4,949.90	4,306.19	3,570.00
Oct-04	4,956.25	4,236.44	3,725.00
Nov-04	4,936.92	4,326.44	3,724.40
Dec-04	4,888.09	4,372.94	3,739.90
Jan-05	4,887.27	3,938.94	3,476.40
Feb-05	4,885.01	3,928.82	3,447.96
Mar-05	4,853.52	3,874.57	3,420.06
Apr-05	4,845.19	3,874.57	3,385.56
May-05	4,805.80	3,851.63	3,349.91
Jun-05	1,699.82	3,851.63	3,349.91

ATTACHMENT 2

ICAP Reform Proposals
In New England and PJM

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ICAP Reform Proposals in New England and PJM

John Chandley[1]

INTRODUCTION

Each of the eastern Independent System Operators (ISOs) has been developing reforms to the installed capacity (ICAP) mechanisms they use to achieve resource adequacy. Following the development by the New York Public Service Commission and the New York ISO (NYISO) of locational capacity markets and the introduction of a downward sloping demand curve for defining capacity payments, the ISOs in New England (ISO-NE) and PJM are proposing to introduce similar concepts in their regions. The ISO-NE and PJM proposals borrow from and refine the two NYISO approaches, while proposing additional features to address some of the issues believed to be limiting the effectiveness of their existing ICAP markets.

This paper examines the ICAP market reform efforts underway in New England and PJM. It first summarizes the conditions, issues and FERC decisions that led to the ISO-New England "LICAP" proposal, which is now before FERC, and to PJM's Reliability Pricing Mechanism (RPM) proposal, which has been under development for over a year and was filed at FERC on August 31, 2005. The paper then examines these two proposals in some detail, focusing on how each proposal attempts to address each of the problems these ISOs are having with their current ICAP markets.

The reform proposals share key features. Both ISOs propose to move from a regionally uniform approach to capacity requirements and prices to locationally different requirements, markets and prices that recognize the transmission constraints that limit the deliverability of capacity from one region to another. And both ISOs would use a downward sloping demand curve to determine capacity prices consistent with the investment requirements for meeting their resource adequacy goals. But the two ISOs approach their respective reforms from two very different perspectives, with New England relying somewhat more on market driven responses to short-run prices and PJM relying more on an integrating planning and long-run acquisition approach overseen by the ISO. The differences are not always sharp; both ISOs use administrative means to establish their respective resource adequacy goals and both administratively define the demand curves that determine the prices to be paid for capacity bought and sold through ISO-administered auctions. Both rely on their respective transmission planning processes to help guide resource adequacy decisions. But here the two approaches separate in ways that illustrate some basic policy choices.

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[1] This paper was prepared at the request of the California Independent System Operator to assist the California ISO in its consideration of alternative mechanisms to assure resource adequacy. The paper has benefited from comments from Scott M. Harvey, William W. Hogan, Mike Cadwalader, and Dmitri Perekhodstev, with research assistance from Alexis Maharam, all of LECG, as well as helpful comments from James Bushnell and the California ISO Staff. The views expressed here are solely those of the author, and any errors are solely the author's responsibility.

The ISO-NE approach focuses on defining the right set of price incentives that will not only support the target level of capacity investment but also allow the market to decide the types and features of capacity resources that the market will build and retain. While the ISO-NE would administer short-run markets to set these prices each month, the philosophical approach is to leave the choice about which investments and operational features to choose largely to the market. The New England approach also tries to focus payments for "capacity" to those who actually provide reliability in real time, rather than simply to any generator that has installed "capacity." At present, the definition does not include demand alternatives, although in theory it could. Locationally different capacity prices are then viewed as a common incentive framework from which the market, more than the integrated planner, can consider alternative investments in generation versus transmission upgrades. In the New England approach, transmission planning would still be performed by the ISO, and identified transmission needs would be affected by the generation market's response to locational capacity prices and hence to local reliability needs, but transmission investment is not otherwise explicitly linked to the generation resource adequacy framework.

In contrast, the PJM approach not only defines the prices to support investments but also has the ISO itself involved in deciding which operational features to reward. The ISO-selected features – such as load following or 30-minute quick-start capability -- are directly rewarded through higher payments; features not selected may not be rewarded at all or rewarded only indirectly. In addition, the PJM approach adopts the integrated planning paradigm by linking a long-run planning approach for transmission expansion with a long-run procurement approach for all infrastructure. The intent is to allow alternative investments in generation and transmission, as well as demand-side response, to compete in the same ISO-administered auction. Moreover, whereas the New England approach apparently accepts the view that short-run capacity auctions and prices can provide a sufficient basis for long-run investment decisions (in conjunction with bilateral contracts and self supply decisions designed to hedge short-run price risks), PJM asserts that short-run prices alone will not provide sufficient encouragement or support for long-run investments.[2] The PJM proposal thus features a series of forward auctions for products to be delivered as much as four years in the future, based on the apparent belief that without such forward obligations, the appropriate investments would not be made.

The reform efforts in PJM and ISO-NE both contrast with a very different approach under consideration by the Midwest ISO. The Midwest ISO (MISO) currently has no explicit ICAP requirement or ICAP markets beyond the sub regional resource adequacy requirements that preceded the formation of the MISO.[3] Rather than further develop an ICAP requirement and offer ICAP markets similar to those in PJM, New York and New England, the Midwest ISO is

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[2] According to the PJM RPM filing, "Future reliability can best be assured through an integrated solution, which supplements transmission enhancement identified in the RTEP process with a system of long-term capacity price signals to encourage new capacity resources to locate in the areas of greatest need." PJM Reliability Pricing Model submitted to the Federal Energy Regulatory Commission (FERC) on August 31, 2005 (PJM Filing), at 45.

[3] The MISO Transmission and Energy Market Tariff does impose a minimum 12 percent planning reserve requirement on load-serving entities, but there are no detailed rules for implementing this requirement, nor are there provisions that would allow the MISO to administer capacity markets. *Midwest ISO Open Access Transmission and Market Tariff Module E - Resource Adequacy,*effective April 1, 2005.

exploring whether an "energy-only" market approach could be implemented in the MISO footprint in lieu of an explicit ICAP requirement. At this time, MISO has only issued a brief "white paper" outlining the concept, in the hope of stimulating further discussion among stakeholders.[4] To allow an informed comparison of this approach, a companion paper prepared for the California ISO by William Hogan examines the theory and concepts behind an energy-only approach for achieving resource adequacy.[5]

This report on ICAP reform efforts in New England and PJM should also be read in conjunction with a recent report prepared by Scott Harvey for the California ISO,[6] which describes and examines the existing mechanisms used by PJM, the New York ISO, and ISO-New England. As noted in the Harvey and Hogan papers, the existing ICAP mechanisms share a common conceptual framework: the notion that because of various caps on the spot market prices paid to generators for energy and ancillary services, adequate generation to meet each region's resource adequacy goals can be sustained only if generators receive a supplemental source of revenues through payments for a product called "capacity" that is different from "energy." Through these supplemental payments, generators are expected to recover the "missing money" caused by the imposition of price caps and other mechanisms that keep energy and operating reserve prices below competitive levels[7] – and hence below levels sufficient to sustain the desired level of investment. The reform proposals in PJM and ISO-NE are based on this same framework.

Common Issues Driving ICAP Reform Efforts in New England and PJM

The ICAP reform efforts in the Northeast appear to be driven by a set of common concerns with the current ICAP mechanisms. The concerns arise partly from the way that the ICAP markets function, but they also arise from how "capacity" is defined and hence what suppliers must do to receive payments for providing capacity. Indeed, the ISO-NE proposal seeks in part to redefine "capacity" as an obligation to provide energy or operating reserves during periods of operating

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[4] Midwest ISO, "Draft Discussion Paper on Resource Adequacy for the Midwest ISO Energy Markets," August 2005 (MISO White Paper).

[5] William Hogan, "On an 'Energy-Only' Electricity Market Design for Resource Adequacy," draft submitted to CAISO, September 2005.

[6] Scott M. Harvey, "ICAP Systems in the Northeast: Trends and Lessons," submitted to CAISO, September 2005. (ICAP Systems)

[7] As explained further in the Harvey and Hogan papers, energy and operating reserve prices in the ISO spot markets can be kept below competitive market-clearing levels by several factors. These include: (1) the imposition of a general "safety valve" offer cap, typically set at $1,000/MWh in eastern ISOs (currently $250/MWh in California); (2) the absence of any explicit shortage-cost pricing mechanisms to allow prices to reflect the value of lost load (VOLL) during shortage conditions; (3) the imposition of unit specific offer caps when an offer fails the "conduct and impact" tests, or in situations involving transmission constraints and the need for redispatch, such as the PJM rule to cap offer prices at cost plus 10 percent when a unit must be dispatched out of merit as part of congestion redispatch or cost plus 40 percent for frequently mitigated units; (4) dispatch, commitment and pricing rules that allow an ISO to hold high cost units at minimum generation (such as for contingency purposes) but thereby prevent these high cost units from setting the market-clearing prices at their locations; and (5) inconsistent pricing between energy and operating reserve markets that fail to reflect shortage values when operating reserves fall below desired levels; and so on.

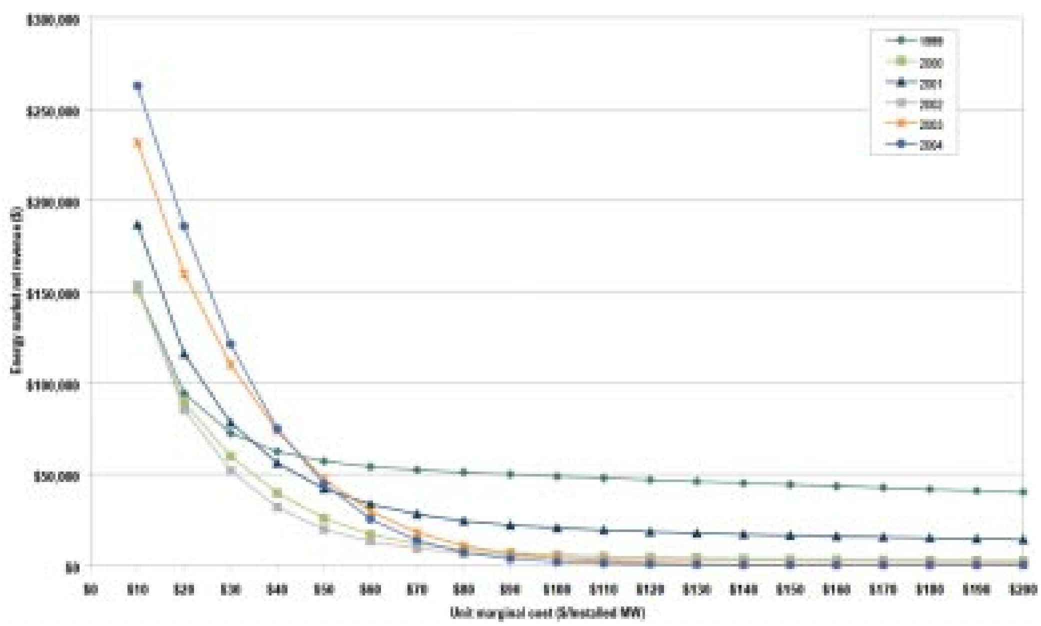
reserve shortages, and the designers use an "energy-only" model as a principal source for guidance in redesigning New England's ICAP mechanism.

Each ISO has a separate history about how their reform efforts came about; key elements of each history are summarized in this section, while a chronology of related FERC filings and Orders appears in two Appendices. But all of the eastern ISOs share several common and closely related concerns with their ICAP mechanisms:

1. Insufficient market revenues to support needed investment in key areas.

Both New England and the original footprint of PJM experienced generation construction booms a few years back, resulting in region-wide surpluses of capacity relative to each of the ISOs' resource adequacy criteria. The regional surplus, as well as offer price mitigation schemes intended to mitigate market power in transmission constrained areas, combined to depress market prices for energy and operating reserves, pushing generation margins – and hence contributions to fixed costs – to near zero for peaking units. The trend of declining margins in PJM is shown in Figure 1.[8]

Figure 1
PJM Energy Market Net Revenue
By Unit Marginal Cost



Source: PJM

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[8] PJM figures are reprinted with permission from a PJM presentation by Andy Ott, "Current Installed Capacity Markets: How Well Have They Worked?" April 11, 2005. These figures also appear in the PJM RPM filing, submitted to FERC on August 31, 2005.

The capacity surplus also caused capacity market prices to fall since 2001 to near zero levels, an effect driven as much by the use of a vertical demand curve (discussed below) as by the capacity surplus. In PJM, this trend was briefly interrupted in 2004, but only because of what PJM found to be capacity shortages caused when a large generation owner physically withheld capacity from PJM's capacity credit markets. The trend in capacity prices in the PJM region is shown in Figure 2.

Figure 2
Prices in PJM Daily and Monthly Capacity Markets

Source: PJM

The combined effect of depressed energy prices and depressed capacity prices has left most generators with insufficient revenues to cover fixed operating costs and investment costs. The problem extends not only to peaking units but also to intermediate and base load units. For example, PJM has estimated that over the last five years, combustion turbines would have earned from margins in the PJM energy markets only about half of the revenues needed to recover fixed costs, while intermediate and base load units would have recovered about two thirds or less of the revenues needed to cover their fixed costs.[9] With capacity prices tending towards zero under

[9] PJM, presentation by Andy Ott, "Current Installed Capacity Markets: How Well Have They Worked?…" April 11, 2005, at 6. The figures appear to compare the annual fixed cost (on a 20-year levelized basis) versus an estimate of the average annual net revenue from PJM markets between 1999 and 2004, suggesting there is little existing incentive for new entry. For similar findings, see Federal Energy Regulatory Commission, *State of the Market Report*, Washington D.C., June 2005, at 60.

the current ICAP designs, generators would likely not have recovered their remaining fixed costs from the sale of capacity.[10]

The result of these trends has been a substantial fall off in proposals for new capacity – only about 111 MW were added in 2003-2004 with another 920 MW under construction. There is almost no new capacity proposed for the region. At the same time, there has been a substantial increase in the number of retirements. In PJM, 1,973 MW of capacity were retired in 2003 to 2004, and owners have proposed an additional 2,400 MW for retirement for the 2005-2007 period, most of this in Eastern PJM (primarily New Jersey). In the meantime, load growth in Eastern PJM was expected to increase capacity requirements by about 2,500 MW. Without significant capacity additions and/or transmission upgrades into the area, Eastern PJM would be unable to meet reliability requirements as early as 2008.[11]

The natural result of these trends in both PJM and similar trends in New England would be an expected decline in the level of capacity surplus, which on its own would not be a cause for concern. However, in both regions, the substantial increase in retirements and the absence of significant new investments have been occurring primarily in local areas of each region that tend to be transmission constrained – that is, in areas where there is a limited ability to move power from surplus capacity from the broader region to areas with high loads and little if any surplus, such as New Jersey in PJM and Boston or Southwest Connecticut in New England. In short, market prices for both energy and capacity were failing to signal and support the investment needed to maintain existing plants or construct new plants in locations with a growing need for capacity.

2. Absence of locational requirements and locational price signals.

All of the eastern ISOs operate bid-based dispatches and corresponding spot markets for energy (and in some cases, operating reserves), in which settlement prices for energy are based on defining the locational marginal price (LMP) at each location. In the case of generators, settlements for imbalances and spot purchases and sales are on a nodal basis – that is, there is a distinct LMP for each generator's bus. However, offer caps and other limits on how high the LMPs can rise during shortage or transmission constrained conditions can prevent the LMPs from reaching competitive market-clearing levels if the caps do more than merely limit the exercise of market power. Logically, this would suggest that if a payment for "capacity" is made to generators to make up for the "missing money" caused by the energy price limits, then these capacity payments might also need to be differentiated at the nodal level. However, although there were locational ICAP requirements in New York, the ICAP requirements and markets in New England and PJM applied a uniform ICAP requirement for the entire footprint of each ISO.

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[10] According to PJM's Market Monitor, " . . .net revenue in the PJM Region has been below the level required to cover the full costs of new generation investment for several years and below that level on average for new peaking units for the entire market period." PJM RPM Filing, Bowring Affidavit, at 15.

[11] PJM, "Immediate Reliability Issues in the Absence of RPM," Attachment B to Letter from Phil Harris to the PJM Members Committee, page 2, posted to the PJM website for the PJM Annual Meeting, April 19, 2005. Also see, PJM RPM Filing, Affidavit of Steve Herling, at 7-8.

This meant each ISO conducted ICAP auctions on an ISO-region-wide basis, deriving a single, uniform clearing price for all capacity in the region, regardless of the capacity's location.

As seen in New York, transmission limitations on the deliverability of capacity between sub-regions of the NY ISO footprint, especially into New York City and Long Island, created locationally different market prices and values for capacity. These considerations convinced the New York Public Service Commission and the member systems of the New York Power Pool to include separate capacity requirements for New York City and Long Island, compared to the rest of New York, in the original NYISO market design, and to limit the extent to which these sub-regional requirements could be met by reliance on capacity located in the "rest of state" ("ROS") zone.[12] This approach allowed monthly prices for capacity to differ between the three sub-regions, but not within each sub-region.

The same considerations affected PJM and New England. Without any location price differences for capacity, the uniform prices paid to generators failed to encourage appropriate generation investment in locations where capacity would be more valuable and contribute more to local reliability. Conversely, the absence of locational price signals failed to discourage investments at locations where capacity was less valuable, including locations where additional capacity would add little if anything to regional reliability. In New England, for example, areas in Maine with lower costs had become attractive locations for new capacity investments, but transmission constraints limited the ability to move that power both out of Maine and into load centers further south – such as Northeast Massachusetts (NEMA) and Boston, as well as Southwest Connecticut. The regionally uniform capacity payment approach tended to encourage further capacity investments in Maine but too little investment in NEMA-Boston or SW Connecticut.

Similarly, in the first years of the PJM markets, the PJM region experienced a boom in new plant construction, allowing the region as a whole to achieve capacity levels above the industry standard of 1-day in 10-years Loss of Load Expectation (LOLE). But at the sub-regional level, this adequacy began to change in 2003-2004, following the announced retirement of several older plants in New Jersey, at the eastern end of PJM.[13]

Until the announced retirements, all capacity in PJM could be deemed "deliverable" to loads by counting the simultaneous contribution from both western and eastern generation.[14] But the announced retirement of significant capacity generation in New Jersey undermined the basis for this claim, exposing a weakness in the "deliverability" concept upon which PJM had been relying. At this point, PJM concluded that, like New York and New England, it too would need

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[12] The capacity requirements that must be met by local generation (and not imports) are set by the New York State Reliability Council.

[13] See, Appendices A and B for summaries of ISO filings and FERC Orders related to retirements, the expansion of RMR contracts and the need to redesign each ISO's ICAP markets.

[14] For a further discussion of the PJM concept of "deliverability" and the difficulties it ran into when the retirements were announced, see pages 20 to 28 in "ICAP Systems in the Northeast: Trends and Lessons."

to have locational requirements and locationally different prices to provide better incentives for ICAP investments in areas affected by transmission "deliverability" constraints.[15]

3. An increase in the number of Reliability-Must-Run (RMR) Contracts

One of the consequences from the absence of locational price signals for capacity is that ISO-NE and PJM began to experience an increase in the number of plants applying for RMR treatment as a way to cover their fixed costs. RMR contracts are typically used with older plants in transmission constrained load pockets where the ISO concludes that specific units are needed for reliability purposes, but revenues from the offer-capped energy markets are not sufficient to cover these plants' fixed costs. To avoid premature retirement of these units, the ISOs contract with the needed plants to remain available, with the contracts typically covering going forward fixed costs that would not be recovered because of limits on energy and/or operating reserve prices.

In New England, RMR contracts had been used for several years, but this problem became more apparent in early 2003 when several independently owned units located in Southwest Connecticut filed with FERC for approval of RMR contracts with the ISO.[16] The Southwest Connecticut region had a history of underinvestment in transmission and generation, with serious limits on the ability of generation outside the local area to meet reliability requirements within the local area.[17] However, in ruling to limit the *Devon* RMR requests, the FERC criticized ISO reliance on RMR contracts on several grounds and directed the ISO to begin developing an alternative, market-based approach that would reduce (if not eliminate) reliance on RMR contracts.[18]

The FERC's criticisms of RMR contracts in the April 25, 2003 Order provide an initial view of what FERC expected from ISO-NE, and presumably other ISOs, with regard to compensating units needed for local reliability. In particular, the Commission expressed concern that the effect of RMR contracts was to remove high cost units from the calculation of the

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[15] PJM RPM Filing, at 5-6.

[16] There were two sets of these filings:

(1) PPL Wallingford's cost of service agreement with ISO New England: *Cost of Service Agreement Among PPL Wallingford Energy LLC, PPL EnergyPlus, LLC and ISO New England, Inc* in FERC Docket ER03-421-000 (January 16, 2003 Filing)
(2) Devon Power LLC, et al's cost of service agreement with ISO New England, which became the lead docket in the development of the ISO-NE LICAP proposal: *Reliability Agreements Among Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, NRG Power Marketing Inc., and ISO New England Inc.* in FERC Docket ER03-563-000 (February 26, 2003 Filing)

[17] Like other ISOs, ISO-NE had specific provisions authorizing the use of RMR contracts in such cases, and these provisions had been approved by FERC when it approved ISO-NE's "Standard Market Design" tariff. *Order Accepting in Part and Modifying in Part Standard Market Design Filing and Dismissing Compliance Filing* 100 FERC ¶ 61,287 (September 20, 2002 Order)

[18] *Order Accepting, in Part, Requests for Reliability Must Run Contracts and Directing Temporary Bidding Rules* 103 FERC ¶ 61,082 (April 25, 2003 Order)

market-clearing prices (LMPs) at each location. Units under RMR contracts might be scheduled by the ISO or committed for local reliability purposes. The units could be held at minimum generation levels and kept available in case of some local contingency, so these high cost units would not set the LMPs, and their incremental energy costs would not set prices within the potentially constrained region. LMPs set at the unconstrained level would exacerbate the "missing money" problem for any other plant selling power within the potentially constrained region but not subject to an RMR contract. The result could in turn lead units that were not currently under RMR contracts to seek cost recovery through RMR or similar contracts, thus systematically undermining the market for a growing percentage of plants.[19] The need for a market-based alternative to the growing reliance on RMR contracts was thus driven in part by a concern that the entire market structure might ultimately be at risk.

In its April 25, 2003 Order limiting the *Devon* RMR contracts, FERC directed ISO-NE to develop a market-based alternative to the growth in RMR contracts. FERC suggested either a locational ICAP approach (as New York had implemented for New York City and Long Island) providing increased compensation to generators located in transmission constrained areas, or some other market-based "deliverability" mechanism that would ensure that capacity developed in other areas would be deliverable to such local areas and be appropriately compensated. FERC did not specify what a "deliverability" option might look like, and a locational ICAP approach had already been implemented (and approved by FERC) in New York and proposed by PJM for its region. In response to the order, ISO-NE therefore chose to develop a locational ICAP (LICAP) approach for New England.

The same issue regarding RMR contracts arose in PJM. There, the announced retirement of several generating units in New Jersey created a concern because some of these units have been relied on for local reliability purposes. PJM did not initially have a formal policy for handling announced retirements, and at FERC's urging, PJM developed rules that would allow PJM to defer a retirement for a limited period and provide compensation to that unit that covers the unit's going forward costs needed to keep the unit operational. In approving this approach, however, FERC made clear that an ISO could not indefinitely prevent a unit from retiring. In addition to providing RMR or other short-run compensation schemes, FERC indicated that an ISO must provide market-based mechanisms that would, as much as possible, address the long-run "reliability compensation issue."[20]

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[19] Rebuttal Testimony of Dave LaPlante, submitted in the ISO-NE LICAP case, Docket ER03-563-030 (LaPlante Rebuttal) at 4-5, 49. The number and range of RMR contract applications has increased substantially during the two years in which ISO has been developing and seeking approval of its LICAP mechanism. New RMR requests have been submitted for nearly 4600 MW, in some cases by newer, more efficient combined cycle plants, not merely older peaking units. LaPlante Rebuttal 4-5. There are currently about 2200 MW of capacity under existing contracts. See also, *California Public Utilities Commission Capacity Markets White Paper*. August 25, 2005 p. 37 (California White Paper)

[20] See, FERC, Order on Tariff Filing, 107 FERC 61,112, May 6, 2004, (May 6, 2004 Order). Filings and Orders leading up to this Order are summarized in Appendix A.

4. Ineffectiveness of "Safe Harbor" Bids in Recovering Fixed Costs

In the ISO-NE LMP-based market rules that FERC approved in its December 20, 2002 Order,[21] the ISO established a mechanism intended to allow seldom used generators in transmission constrained areas to submit bids high enough to recover both fixed and operating costs, provided these plants were actually dispatched, and their bids actually set the market-clearing LMPs often enough. This mechanism, called the "CT Proxy," allowed generators in transmission constrained areas to increase their energy offers above levels that would otherwise be subject to market power mitigation to give them an opportunity to recover their fixed costs in energy prices.

In its April 25, 2003 Order in the *Devon* case, FERC directed ISO-NE to replace the CT Proxy mechanism and substitute a conceptually similar approach that would allow seldom run (10 percent capacity factor or less) peaking units in locally constrained areas to submit "safe harbor" bids. Peaking Unit Safe Harbor (PUSH) bids would be defined by the amount of revenues a seldom dispatched peaking unit would need to recover from the ISO's energy market if its bids set the clearing price and if the peaking unit were dispatched the same number of hours as in the preceding year. Bids at or below the PUSH levels would not otherwise be subject to the ISO's offer mitigation rules. As with the CT Proxy approach, FERC apparently hoped that by creating a safe harbor for higher energy price offers, the PUSH bidding mechanism would raise LMPs in constrained areas high enough to replace the "missing money" and thus eliminate or greatly reduce the need for RMR contracts. FERC directed ISO-NE to use the PUSH bidding mechanism on an interim basis -- until ISO-NE implemented a locational ICAP or other deliverability mechanism.[22]

The PUSH mechanism never worked as advertised and so did not reduce the need for RMR contracts. In a December 4, 2003 report back to FERC on its experience with PUSH, the ISO-NE noted that the mechanism had so far failed to allow the affected generators to recover their fixed costs and failed to eliminate the need for RMR contracts for the affected units.[23] ISO-NE cited several reasons for this apparent failure, but three related reasons seem particularly relevant:

(1) The permissible level of a PUSH bid for each unit is determined by the number of hours that unit was dispatched in the prior year, but there was no reason to expect the prior year's dispatch would be a useful indicator of this year's dispatch. A significantly lower level of dispatch in the current year compared to the prior year could result in failure to cover a given unit's fixed costs, even if the higher PUSH bids set the LMPs. While this might average out over several years, the variability from year to year could

[21] ISO-NE implemented the new market rules on March 1, 2003.

[22] Generators in PJM also proposed "safe harbor" bidding mechanism for that region. See, Reliant, *Request for Approval of a Formula Proxy CT Methodology for Certain Reliant Energy Mid-Atlantic Power Holdings, LLC Generating Facilities in PJM Interconnect*, FERC Docket EL03-116-000. Although FERC rejected this request, the issue sparked a FERC reevaluation of reliability compensations issues for the PJM region. See Appendix A.

[23] ISO-NE, *Review of PUSH Implementation and Results* in FERC Docket ER03-563-025. December 4, 2003. (December 4, 2003 Report)

expose each unit to substantial risks, but without matching the change in compensation to the incentives needed during stressed hours in real time.

(2) Although the ISO often committed PUSH eligible units for local reliability reasons, they were not dispatched in enough hours to achieve cost recovery. One reason was that the number of hours dispatched in a prior year was based on the units submitting lower offers (possibly mitigated); when the same units submitted higher PUSH bids, they were less often economic and so were dispatched less often.

(3) PUSH eligible units were often committed for local reliability reasons, and they were often held at minimum generation levels as 2nd contingency reserves. This meant the units would not be dispatched for energy except when the 2nd contingency occurred. Under the ISO's pricing rules, units operating at minimum generation are not on the margin and hence not eligible to set the market-clearing LMPs, even though their PUSH bids might be significantly higher than the units actually on the margin and setting the LMPs. At the same time, the 2002 New England market rules had eliminated market-based payments for reserves, including those held for 2nd contingency purposes.[24]

In sum, although PUSH eligible units did submit higher bids than in the past, their bids did not set the LMPs often enough to allow the units to recover their fixed costs.

The concept of a "safe harbor" implies that offer prices that would otherwise be subject to market power mitigation would be permitted to set market-clearing prices. That is, absent safe harbor status, the offer price would have been sufficiently above assumed operating costs of the unit that the offer prices would have been viewed under the market rules as efforts to exercise market power through economic withholding. There was considerable discomfort among state regulators and load-serving entities about any mechanism that permitted very high generation offers. Hence, the PUSH mechanism lacked support from both generators (because it didn't seem to be working) and loads (because they feared it might become a shield for market power).

The PUSH bidding mechanism is still in effect in ISO-NE. Under FERC's Order, the interim mechanism must stay in place until ISO-NE implements LICAP or some other mechanism to address the reliability compensations issues and the growth of RMR contracts. But there have been no further efforts to extend the use of the PUSH or similar concepts beyond the interim period.

5. Vulnerability of ICAP Markets to Market Power

Existing ICAP markets in the Northeast have been criticized for their vulnerability to the exercise of market power, such as through physical withholding in the monthly ICAP markets (or the effect on forward bilateral markets of the threat of such withholding in the ICAP spot market).[25] The motivation and opportunity for withholding stems from the fact that in the PJM

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[24] PJM has since implemented a forward market for operating reserves.

[25] ICAP withholding not only raises capacity prices for remaining capacity but can also reward a generation-owning LSE through the allocation of high deficiency charges paid by other LSEs unable to contract with capacity because

and ISO-NE monthly ICAP markets, the demand for capacity is fixed at the planning reserve margin target corresponding to the regional reliability requirement (1-day in 10-years LOLE), and the supply for capacity is almost fixed, since it is relatively inelastic in the short run. The ICAP markets were thus characterized by a vertical demand curve and a near vertical supply curve in the region where supply crosses demand and sets the ICAP price. In this situation, a small amount of withholding can force a relatively large increase in price, especially if the amount of offered supply is fairly close to the planning reserve margin target, as shown in Figure 3.

Figure 3
Incentives to Exercise Market Power

The combination of a vertical demand curve and a near-vertical supply curve presents strong incentives to exercise market power.

- Any withheld supply shifts the Supply curve to the left
- A slight shift of the supply curve to the left causes a large increase in price.
- This can easily offset the revenues foregone as a result of withholding.

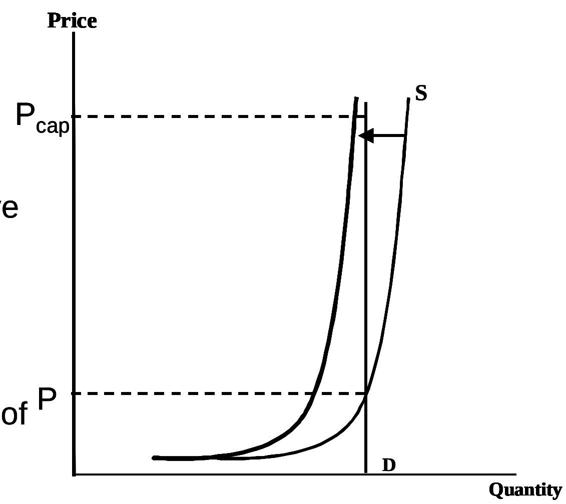

Figure 3 also illustrates that capacity markets characterized by vertical demand curves and near vertical supply curves in the short run can exhibit extreme price volatility. When supplies slightly exceed the fixed reserve requirement, capacity prices in the monthly markets can fall close to zero and remain near zero as long as there is just enough capacity to meet the fixed reserve requirement. (This partly explains the near-zero capacity prices observed in these markets, as shown in Figure 2.) But when supplies are slightly less than the fixed reserve requirement, capacity prices rise rapidly to the administrative price cap for capacity (sometimes called the “deficiency charge”). Extreme price volatility for capacity can create risks for both LSEs and their consumers. It can also increase investment risks for those contemplating capacity

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of the contrived capacity shortage. In PJM, these penalty revenues were allocated to those LSEs who were fully covered with ICAP contracts. But these might be LSEs that were also large generation owners with incentives to withhold their surplus capacity. See, MMU, “Report to the Pennsylvania Public Utility Commission, Capacity Market Questions,” November 2001.

additions when suppliers are near the reserve target, since a relative small change in the quantity can dramatically lower prices and eliminate expected returns on investment. And because the volatility is highly unpredictable, both buyers and sellers face risks in defining a capacity price for forward contracts.

There are several approaches for discouraging or mitigating market power in the ICAP markets. The focus here is on two particular options developed by the ISOs:

(1) *Change the demand curve*. The profits from exercising market power can be reduced by replacing the vertical demand curve with a downward sloping demand curve.[26] This is the approach pioneered by the NY ISO; it is now proposed in both ISO-NE and PJM. (The derivation of these curves is described later in this paper.) Note however, that although the profits from withholding would be reduced by the sloped curve, they would not be eliminated; hence there remains some incentive and opportunity to exercise market power through either physical or economic withholding of capacity. In the PJM and ISO-NE proposals, concern for this residual opportunity gives rise to further efforts to reduce market power if the ISO relies primarily on the downward sloping demand curve and monthly ICAP auctions to set ICAP prices. In the case of PJM, a principal method is to mitigate capacity offer prices in the periodic auctions or to compel suppliers to submit offers; in the case of ISO-NE, the proposed method is to count all installed capacity (net of exports), whether or not it is offered in the monthly auction, when setting the price from the demand curve. These approaches are described further below.

(2) *Change the supply curve*. Market power might also be reduced or eliminated by moving the obligation period sufficiently forward to allow new entry to occur; in effect this extends the supply curve to the right. This approach redefines the capacity product to be offered in each auction as a product that does not have to be "delivered" until three or four years from the auction date. The extended period gives new entrants sufficient time to permit and build new capacity, potentially undermining any attempt to withhold existing capacity from the auction. This approach was developed in a joint study prepared by NERA for PJM, NY-ISO and ISO-NE.[27] The concept is now part of the PJM reform proposal called "Reliability Pricing Model." So far, neither NYISO nor ISO-NE has proposed this forward obligation auction approach, although there has been some interest among New England intervenors who oppose the ISO-NE LICAP proposal.[28]

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[26] This approach is sometimes called the "demand curve" approach, but more accurately, it might be called the "*downward sloping* demand curve" approach. The current markets all use "demand curves," but in PJM and ISO-NE, the current "curves" are vertical, reflecting a fixed reserve requirement that does not change depending on price.

[27] Meehan, Eugene; LaCasse, Chantale; Kalmus, Philip; Neenan, Bernard. *Central Resource Adequacy Markets for PJM, NI-ISO and NE-ISO*. Prepared by NERA. February 2003.

[28] Maine regulators originally suggested a version of this forward auction approach as an alternative to the ISO-NE downward sloping demand curve. Another version of the forward obligation approach, based on an auction for option contracts, was offered by Connecticut parties in the LICAP hearings, but it was excluded by the ALJ as beyond the scope of the hearings, on the grounds that FERC's June 2, 2004 Order had limited the hearings primarily to how the parameters of the ISO demand curve should be selected. See *Initial Decision* 111 FERC ¶ 63,063 (Initial Decision) at 157-158. However, at a September 20, 2005 hearing for oral argument in the LICAP case, FERC allowed parties to describe alternatives to the ISO-NE LICAP proposal. In that hearing, regulators for four of the six

6. Uncertainty of capacity availability when it is most needed

ISO capacity markets in the East originally counted all "installed" capacity (hence "ICAP") towards meeting the fixed reserve requirements. However, capacity is not always available, and different units may have different levels of availability based on several factors. To partly account for these differences, the ISOs, beginning with PJM, developed the concept of "unforced capacity" or "UCAP." A unit's UCAP rating is a way to discount the capacity for which a given unit is given credit (or is entitled to sell) by adjusting its ICAP rating by a measure of its forced outages. For example, a unit with a nominal capacity of 100 MW might have an effective forced outage rate (EFORd) of 10 percent, suggesting that *on average*, the 100 MW unit had 90 MW of UCAP available. Given its UCAP rating, the unit would receive capacity payments for 90 MW, rather than 100 MW.

A UCAP rating would account for average availability over the year (or over a season), but it would not tell the ISO whether a plant was actually available in those hours in which the capacity was most needed, such as those hours when the operating reserves available to the ISO fell below the target reserve level. The ISOs therefore needed an additional mechanism to encourage generators to make their capacity available. Two mechanisms have been used by the eastern ISOs:

(1) *A must offer requirement*. Eastern ISO rules generally require any unit that wishes to receive capacity payments to offer its capacity to the ISO in the day-ahead market. To meet this requirement, the unit must either schedule (through a self-schedule or bilateral schedule) its capacity in the day-ahead market, submit an energy and/or operating reserve offer in the day-ahead market, or make its capacity available to the ISO's day-ahead unit commitment process.[29]

(2) *Penalties for failure to be available*. Any unit seeking to be paid for capacity that fails to meet the ISO's availability requirements (such as the must offer requirement) will incur a penalty charge set by the ISO market rules. The penalty is typically set at some fraction of the fixed costs of a combustion turbine, defined on an annual (or seasonal) basis. Units with approved maintenance schedules may be exempt from such penalties.[30]

The current availability requirements tend to suffer from several problems. First, the availability metric – UCAP adjusted for EFORd -- is an average. It fails to account for the

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New England states supported a form of the forward auction model with locational requirements (but no sloping demand curve) and the other two states' regulators supported the forward auction model but without locational requirements (and no sloping demand curve). For a description of the option contract auction proposal, see Bidwell, Miles, "Reliability Options," , *The Electricity Journal*, Volume 28, Issue 5, page 1.

[29] PJM Operating Agreement. Sheets 93-94. New England ISO Manual for Market Operations at 2-11.

[30] E.g., see NYISO Installed Capacity Manual 5.2 at 39-40. Available at http://www.nyiso.com/public/documents/manuals/planning.jsp

different value of capacity at different times and conditions, depending on how close the ISO is to falling short of capacity.

Second, the availability metric relies to some extent on self reporting by generators, but there may be an incentive for generators to not fully report outages that are not obvious. For example, if a unit is not dispatched on the day because its offer price is above the clearing prices for that day, but during that day the unit experiences a maintenance issue that would make it impossible to operate if it were actually called, it is not clear that the unit owner would report this as an outage that might affect its EFORd and UCAP. Having already concluded that the unit was not needed on that day, the ISO would have little reason to take steps to confirm the unit's operational availability.

Third, the penalties assessed for non-availability are administratively determined and fixed in the ISO tariff. But these penalties are unlikely to reflect the costs to the ISO of a unit's failure to be available. Limiting the penalties to some fraction or multiple of the annual cost of a CT is not likely to be the economically correct signal that reflects that unit's impact on market prices. Moreover, the energy market prices themselves are capped and hence do not reflect the value of shortages that may result from a unit's non-availability.

In its LICAP proposal, the ISO-NE is attempting to address this set of issues by changing the availability metric and moving to a market-based price for "penalties." As discussed below, ISO-NE proposes to replace the current UCAP/EFORd metric and instead measure availability by whether a unit is actually providing energy or operating reserves during an hour in which the ISO experiences a shortage in the target level of operating reserves. A unit unavailable during "reserve shortage hours" would see its capacity payments correspondingly reduced, while a unit that was available during those hours would see its capacity payments increased. The features of this reserve shortage hour metric and comparisons with the current UCAP/EFORd approach are described in more detail below.

7. Lack of Incentives for Features that Support Reliability (or Assure Availability)

A principal reason for the increased need for RMR contracts is the fact that current market rules and pricing mechanism may not sufficiently compensate generators that provide features and attributes essential for reliable operations or valuable to the ISO in implementing a reliable and economic dispatch. Some of these essential reliability features are simply not priced directly or at all in today's markets, such as voltage support or black start capability. Higher energy prices alone cannot provide the appropriate incentives for the supply of these services, and additional markets or pricing mechanisms would seem necessary.

Efficient energy and/or operating reserve pricing, however, could encourage other features, but the incentives are blunted by price and offer caps or other rules that suppress energy market prices below competitive levels or by the absence of effective markets for operating reserves. For example, efficient market-clearing prices during reserve shortage hours would reflect the shortage and thus tend to be high enough to encourage investments and operational decisions that make it more likely that a unit would be available when needed. Such prices might, for example, encourage more investments in quick-start units, or units that could be cycled on/off more often, or units with faster ramping rates; they might also encourage unit owners to change their fuel purchasing habits to ensure fuel during expected peak conditions or reserve shortage hours or to invest in dual-fuel capabilities to manage the risks of gas shortages during winter peak periods, and so on. However, since price/offer caps limit the level of energy prices during these same periods, they also blunt the incentives to take these and other steps that allow generators to be available when they are most needed.

As currently structured, ICAP payments do not solve these problems, because the UCAP availability metric measures average availability and because the administrative penalty structure does not necessarily mimic the incentive properties of uncapped shortage-cost pricing. As a result, the incentives for both operational and investments decisions that affect real-time availability are not efficient, likely resulting in a more costly mix of generator characteristics than those that would minimize the cost of maintaining reliable operations.

In their reform efforts, PJM and ISO-NE have approached this incentive problem in two very different ways. The PJM approach is to have the ISO identify specific generation features that it would like to encourage – such as quick-start capability and dispatch flexibility – and specifically reward those identified characteristics in the ICAP auctions. Those units that have the selected features are paid a higher price in the auction; those without them are paid less. Since the ISO makes the choice of which features to reward, this has the characteristics of an integrated planning approach, but it also means that other measures that might also be valuable for maintaining reliability may not be undertaken, because they are not explicitly rewarded.

In contrast, the ISO-NE proposed approach is to measure availability based on whether a unit was actually available during those hours in which the ISO falls below its target level of operating reserves. Compensation then depends on whether a unit was or was not providing energy and/or operating reserves during these stressed hours. Since compensation depends on actual availability during these hours, the concept attempts to provide a strong market signal to generators to make whatever steps and investments they think are justified to improve the changes of actual availability. Under this approach, the ISO does not attempt to single out specific features to reward; rather, its goal is to reward any combination of features that enhances actual availability of units when they are most needed. Unlike the integrating planning model proposed by PJM, the choice of which mix of measures to pursue is left to the generators and the market to sort out. These contrasting concepts are discussed in more detail below.

The Sections that follow describe the ISO-NE and PJM proposals in more detail. The discussion is organized to focus on how each ISO attempts to address the several concerns above.

THE ISO-NEW ENGLAND LICAP PROPOSAL

The ISO-NE filed its original LICAP proposal at FERC on March 1, 2004.[31] This original version was revised following a FERC Order approving the two key elements, a locational ICAP market and the use of a downward sloping demand curve, and suggesting a separate LICAP zone for Southwest Connecticut.[32] The ISO subsequently proposed a separate LICAP zone for that area, which FERC approved.[33] In its June 2, 2004 Order, FERC set the specific design parameters of the curve and a limited number of other issues for hearings, which began in late 2004. When the ISO filed its initial testimony for these hearings on November 4, 2005, the ISO further refined key parameters of its proposed demand curve, and it is this revised version of the curve, and further changes in other features introduced in ISO-NE rebuttal testimony, that are discussed below.

The original ISO filing contained most of the elements of the current proposal, and one additional feature – a four-year phase in for LICAP payments -- that the ISO hoped would attract support for the overall LICAP mechanism from load serving entities and New England regulators. During the phase in, LICAP payments would be initially capped, with the caps rising each year, to avoid a one-time rate shock. At the same time, additional compensation would be provided directly to generators in each region, with the costs recovered from loads in the respective regions.[34] The phase in features failed to entice parties into supporting the ISO proposal, and this feature was not endorsed by the FERC June 2, 2004 Order. ISO-NE did not pursue a phase in or other transition feature thereafter.[35]

There are five major components of the ISO-NE LICAP proposal.

1. *The ICAP structure would be locational*. As the term "LICAP" implies, the ICAP structure in New England would recognize five different Locational ICAP zones in which ICAP prices could be different. The five zones include (1) Maine, which is recognized as a transmission constrained generation pocket, (2) the Northeast Massachusetts (NEMA) and Boston region, an area generally recognized as a transmission constrained load pocket, (3) Connecticut, into which there is limited transmission capacity from the rest of New England, (4) Southwest Connecticut, into which serious transmission constraints limit the transfer of power even from the rest of Connecticut, and (5) the rest of ISO-NE footprint ("rest of pool"). The designation of LICAP zones implies the need to define how much of the capacity

[31] *Compliance Filing of ISO New England Inc.; Devon Power LLC, et al* in FERC Docket ER03-563-030 (March 1, 2004 Filing).

[32] FERC, *Order on Compliance Filings and Establishing Hearing Procedures* in Dockets ER03-563-030 and ELO4-102-000 (June 2, 2004 Order).

[33] *Compliance Filings of ISO New England, Inc.* July 2, 2004 in FERC Dockets ER03-563-039 and EL04-102-002 (July 2, 2004 Filing)

[34] March 1, 2004 Filing, at 6.

[35] Appendix B contains a timeline and summaries of relevant ISO-NE filings and FERC Orders.

needed to meet an area's reliability requirement must be located inside each zone and how much can be imported from the rest of New England, a neighboring zone or neighboring ISO or control area. It also implies some method to allocate the rights to that import capability, either on a financial or physical basis. These issues are developed further below.

2. *The LICAP mechanism would use a downward sloping demand curve.* The downward sloping curve would replace the existing vertical curve, which is based on a fixed planning reserve requirement defined by the region's 1-day in 10-year LOLE reliability criterion. A downward sloping curve implies that the level of capacity reserves varies with price, reflecting the intuitive notion that if capacity is cheap, consumers might be willing to buy more than the target level of capacity, but if capacity is expensive, consumers might be willing to buy less than the target level of capacity. It also reflects the notion that levels of reserves higher than a nominal reserve target have some positive reliability value (hence the value of incremental capacity is not zero), while capacity has a higher value when reserve levels are below (less than) the reserve target. In specifying the curve, the ISO also expanded the definition of the region's reliability standard. That is, the curve is designed not only to achieve the 1-day in 10-year LOLE, on average, but also to ensure that the level of capacity does not fall below the level required to meet the 1-day in 10-year LOLE criterion more often than has been historically the case over the last two decades. The design details and rationale of the ISO-NE's proposed demand curve, and responses from stakeholders to its various parameters, are described further below.

3. *The ISO-NE proposal significantly changes the availability metric to encourage availability during reserves shortage hours*. Under the proposal, generators would begin with a capacity rating adjusted by forced outage rates (EFORd), just as occurs under the current UCAP approach. However, this initial rating for each unit would thereafter be adjusted up or down depending on whether the unit was or was not "available" during each hour in which the ISO experienced a shortage of operating reserves.[36] The updating of the availability factor would occur after each shortage hour, and the result at the end of the month would be applied to payments in the following month. The intended effect would be to reward generators that are actually available during those hours in which their energy is most needed for reliability and most valuable to the ISO, and to penalize generators that, *for almost any reason*, are not available during those stressed hours.[37] In this context, "available" means the unit is either producing energy during that hour or providing operating reserves (or is capable of providing such reserves, such as a unit that can start up within 30 minutes). A formula would be

[36] An operating reserve shortage hour is any hour for which the operating reserves available to the ISO fall below the threshold defined by ISO Operating Procedure 4 *ISO New England Operating Procedures.* February 1, 2005.

[37] The ISO-NE has not developed final rules for its proposal, so it is unclear whether there would be any exceptions to this general rule. During the hearings, ISO-NE witnesses generally took the view that there would be few if any exceptions.

used to calculate the up or down adjustments in each unit's availability factor after each reserve shortage hour. Further details about this approach and some of the issues it raises are discussed below.

4. *The proposal would count all capacity in defining the LICAP price*. The ISO added this feature to address arguments offered during the hearings by FERC Staff that even with a downward sloping demand curve, generators might still be able to exercise market power through physical or economic withholding. Under existing ICAP rules, generators offer their capacity in the monthly or seasonal (New York) ICAP auctions, and prices are defined where the supply curve formed by such capacity offers crosses the demand curve for capacity. Physically withholding capacity from the auction could therefore raise the clearing price,[38] and so could higher capacity offer prices. To avoid this result, the ISO-NE pricing mechanism would count all ICAP in the region, including imports and net of exports. Capacity would be counted whether or not it was offered in the auction and even if it was temporarily mothballed. The point where this total quantity of ICAP meets the downward sloping curve would define the auction price for LICAP. Generators would still submit price offers in the monthly auction, but these offers would *not* define the auction price; they would merely determine which offers were accepted – that is, which generators sold capacity in that month's auction and which would be paid, but not how much they would be paid. This feature and its attributes are discussed further below.

5. *LICAP payments would be reduced by profits earned in the energy markets by the "benchmark" unit.* Recall that a central purpose of an ICAP payment is to replace the "missing money" resulting from the caps on spot energy prices. Capacity payments should thus allow recovery of a unit's fixed costs. But generators dispatched in the energy markets could also receive a contribution to their fixed costs from energy prices; the contribution would be the difference between the clearing price at their location (LMP) and their operating costs. The remainder of a unit's fixed cost would need to be recovered through the ICAP payment. Therefore, to ensure that generators are not paid twice for that portion of the fixed costs covered by the energy prices, the ISO-NE proposal reduces the LICAP payments, as defined in each month's LICAP auction, by the profits that would be earned in the energy market by the "benchmark" generator during peak hours. This amount is called the "peak energy rental" (PER) in the ISO-NE proposal.[39] In general, the payment to each generator eligible for LICAP payments is the LICAP price for that month minus the PER for the benchmark generator. The LICAP payment would be further adjusted by each generator's availability factor for that month, which would be recalculated after each shortage

[38] How much it would raise the ICAP price would depend partly on the slope of the curve. A steeper slope leads to a larger change in price for any given change in quantity; a flatter slope leads to a smaller change in price for the same change in quantity.

[39] ISO-NE defines the "benchmark" generator as a frame simple cycle combustion turbine unit.

hour and applied for the subsequent months to reflect whether or not that unit was available during any reserve shortage hour that occurred in the prior month.[40]

Design of the ISO-NE Demand Curve

A defining characteristic of the ISO-NE proposed demand curve is that it is administratively designed. The curve is not the product of actual consumers/buyers expressing a willingness to pay various prices for various quantities of capacity. The latter approach is not possible, *given* the starting point of capped energy prices, the general absence of real-time pricing and corresponding lack of demand-side response. In other words, by accepting energy market price caps as a practical or political necessity, and lacking the support to pass even capped hourly spot prices through to end use consumers, the ISO begins with a condition in which consumers/buyers are not able to indicate how much they would be willing to pay for different levels of capacity or reliability. Given these constraints, there is no clear mechanism for consumers/buyers to indicate their individual value of lost load (VOLL) – that is, the prices each of them would be willing to pay to avoid involuntary curtailments. In the absence of this critical market information, any "demand curve" used to define prices must be specified administratively.[41]

In the case of the ISO-NE demand curve, the parameters of the curve were specified primarily by the ISO, but with an implicit recognition of the role of state regulators as holding the proxy for consumers. How consumers' wishes are properly represented, and by whom, can be controversial, as shown by the universal opposition to the ISO's proposed curve by the utility regulatory commissions for each of the six New England states. The opposition reasons are discussed further below. For the moment, the focus is on how the ISO specified a curve that, it claims, is consistent with accepted regional reliability standards.

A second essential design feature of the ISO-NE demand curve is that there is an intended link between the curve's specifications and the investment requirements for the level of reserves corresponding to the region's reliability objectives. The curve is designed such that *on average* the monthly ICAP payments derived from the curve would provide the ISO's estimate of the missing contribution to fixed costs that investors would need to break even when the level of reserve capacity satisfies the regional reliability objective.[42] According to the ISO's witness, the explicit link between the curve's design and the reliability goal is important because it means that changes in any individual parameter of the curve may affect the amount of investment likely to occur and hence whether it does or does not meet a given reliability standard. Different parameters can result in different curves, and other curves may be reasonable, but to meet the

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[40] If no reserve shortage hours occurred during the prior month, each unit's availability factor would not change from the prior month.

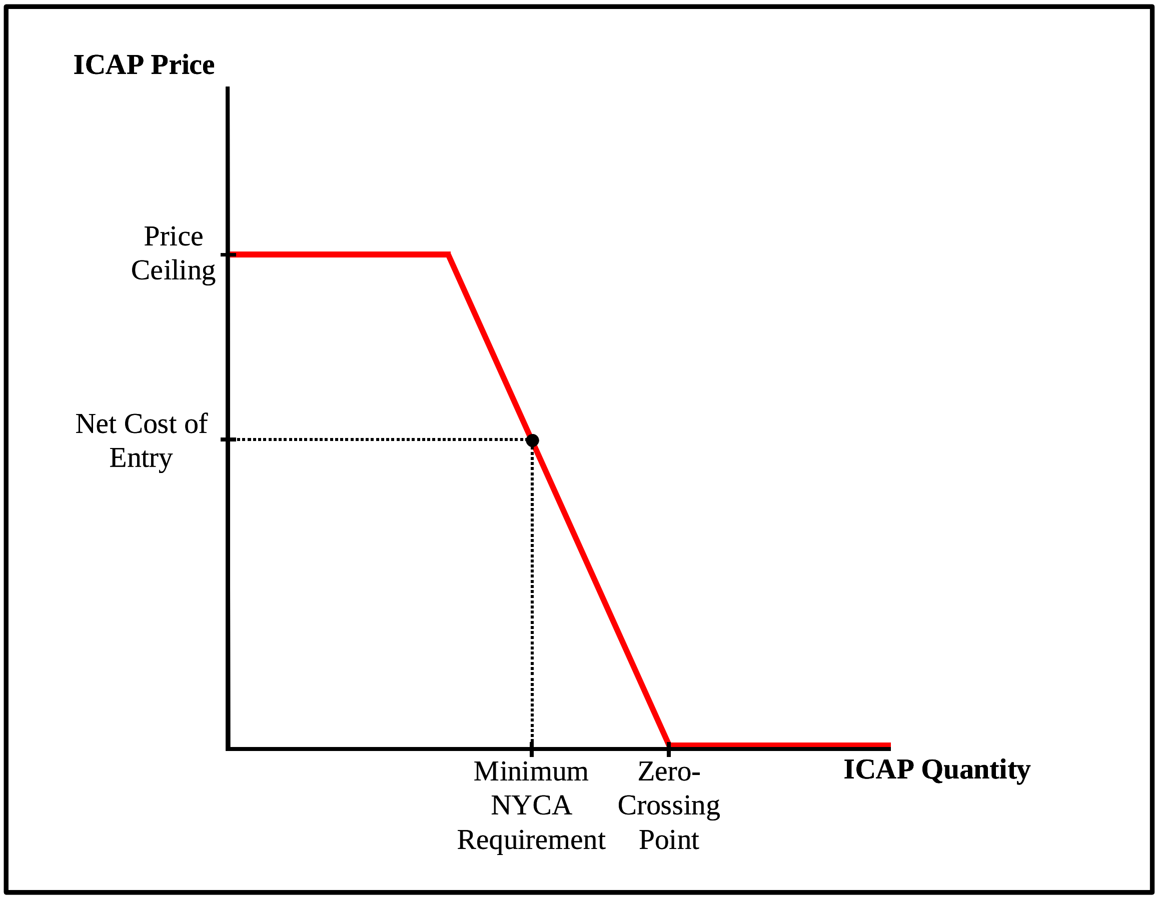
[41] See, *Prepared Rebuttal Testimony of Steven Stoft on Behalf of ISO New England Inc,* in FERC Docket ER03-563-030, February 10, 2005 (Stoft Rebuttal). Similar arguments appear in the California PUC Staff White Paper at 4. The Hogan paper returns to this question and examines how an uncapped energy market might function if these imposed constraints were removed.

[42] See, *Prepared Direct Testimony of Steven Stoft on Behalf of ISO New England*, in FERC Docket ER03-563-030, (Stoft Direct) at 16-17. Compare California PUC Staff White Paperat 18-20. In the White Paper, this type of curve is called a "Fixed Cost Recovery" curve.

same reliability standard, any change in one parameter may need to be offset by compensating changes in one or more other parameters.[43]

The ISO-NE proposed demand curve is a refinement of the concepts underlying the New York ISO demand curves. To understand these refinements, consider first the basic features of the NY ISO curve. Figure 4 illustrates the key features.[44]

Figure 4
NYISO ICAP Demand Curve



The New York demand curve is drawn by specifying a few key parameters, and then basically connecting the dots. The key parameters shown in Figure X are:

(1) The reliability goal or standard. It is shown here as "minimum NYCA requirement," which is the level of reserves above expected peak demand necessary to meet the 1-day in 10-year LOLE adopted by the New York State

[43] Stoft Rebuttal at 37:7-20.

[44] This is a generic curve to illustrate the concepts. Further description of the current NY ISO demand curves appears in Harvey, "ICAP Systems in the Northeast: Trends and Lessons," at p. 51-60.

Reliability Council, which has responsibility for setting reliability standards in New York.

(2) The "net cost of entry," for the type of capacity assumed to be the lowest cost way to add new capacity. As in other ISO ICAP markets, the assumed benchmark unit is a frame, simple cycle combustion turbine. The "cost of entry" is the monthly fixed cost of that capacity, in $/MW-month. The "net" aspect is an adjustment to reflect the peak energy rentals that would be earned by that unit in the energy markets. The NY ISO uses a forecast of such rentals.[45] In the ISO-NE curve, the "cost of entry" concept is captured by the term, "EBCC," which standards for the ISO's estimate of the benchmark unit's capital cost. As discussed below, however, the ISO-NE approach does not net out the peak energy rentals at this point; instead it subtracts these peak energy rentals for the benchmark unit when it determines the LICAP payments, in an effort to achieve a similar purpose.

(3) The first point of the curve is thus the intersection of the two previous parameters: the net cost of entry and the minimum NYCA requirement. The curve can now be drawn through this point. This point can be understood as defining the break-even point for investment. If the level of capacity is at this level (the minimum requirement), the ICAP payment defined by the curve would be exactly the amount needed to cover the net fixed costs of that level of investment, no more, and no less (assuming that the ISO accurately estimated the net cost of entry).

(4) The next point on the New York curve is the "zero crossing point." In the ISO-NE curve, this point will be called C_{max}. It refers to that level of reserves when price falls to zero. Reserve levels less than (to the left of) that point will receive some positive ICAP payment; but if reserves equal or exceed that amount, ICAP payments will be zero. The concept is that once the region has this amount of excess capacity beyond its minimum or target level, capacity has no value and no generator receives any capacity payment.

(5) The final point on the cure is defined by what is, in effect, a price cap on capacity. In the NY curve, it is called Pricing Ceiling; in the ISO-NE curve, the same idea is represented by some multiple of EBCC. For the original NY curve, this cap was about 1.5 times the net cost of entry; in the ISO-NE curve, the proposed cap is 2.0 times the EBCC.

Given these few key parameters, the ISO can draw the curve connecting the points, as shown in Figure X above. In each monthly UCAP auction, generators in New York offer their

[45] The "net" aspect is based on a forecast of the revenues that the hypothetical CT unit would earn over the course of a year from the sales of energy and ancillary services, over and above the costs associated with providing the energy and ancillary services, if conditions were at the long-run equilibrium (i.e., the amount of capacity in the state was equal to the minimum capacity requirement, both statewide and in the New York City and Long Island regions). The New York ISO uses a model to estimate these net revenues.

capacity at various prices, and the ICAP payments are defined by the intersection of the resulting supply curve and the administratively defined demand curve. Generators whose capacity clears the auction receive the auction clearing price for their zone for that capacity. LSEs that are short of capacity coming into the auction pay the ICAP price for the amount of megawatts to cover their shortage; LSEs with excess capacity that clears the auction receive the ICAP price for that capacity.

Deriving each of these points requires an administrative process. For example, the ISO studies the costs of constructing and operating a CT, and the ISO develops estimates of the expected revenues that a combustion turbine unit would receive in the capped energy markets. The minimum requirement is set by whatever authority is responsible for setting reliability standards, in the New York case, the Northeast Power Coordinating Council and the New York State Reliability Council.[46] In ISO-NE, this would be the Northeast Power Coordinating Council (NPCC); in PJM, it would be PJM acting in lieu of, or conjunction with the regional reliability councils of MAAC, ECAR, MAIN and SERC. The capacity price cap and the zero crossing point are matters of judgment, based partly on how steep the ISO wants the curve to be, but also bearing in mind the total investment objective defined by the curve.

The slope of the curve affects the strength of incentives to invest in new capacity or retire existing capacity. But the slope is defined by where the entity drawing the curve sets the zero crossing point and the capacity price cap. Moving the zero crossing point to the left while keeping other parameters constant, for example, would make the curve steeper (or end payments for capacity sooner, as will be seen in the PJM curve), while moving it to the right would make it flatter. A steeper curve would more rapidly increase incentives to invest (relative to a flatter slope) when reserves are less than the minimum requirement, because the prices rise faster as shortages increase; a steeper curve on the right side of the break-even point also increases the incentives to retire costly units when reserves are above the minimum, because prices fall quickly below the break-even point. Similarly, a higher capacity price cap would increase the incentive to invest when reserves fall further below the minimum requirement. At the same time, a steeper curve on the right side may also increase the risks of investing even a little too much; with a steeper curve, a small amount of overbuilding risks failing to receive capacity payments sufficient to break even on the investment.

Loads and generators might therefore perceive the key parameters in different ways, requiring the ISO (or FERC) to take a more detached view and/or arbitrate the conflicting stakeholder positions. Loads (and state regulators), for example, might be concerned that very high ICAP price caps would increase the incentives to exercise market power through withholding. The steeper the curve, the higher the potential profits from withholding when reserve levels are above the minimum requirement, unless market power is addressed in some other way.[47] Generators, on the other hand, might point out that a very flat curve with a low price cap could significantly undermine both incentives to invest when reserves were below the minimum required and the incentives to retire when reserves were above the minimum.

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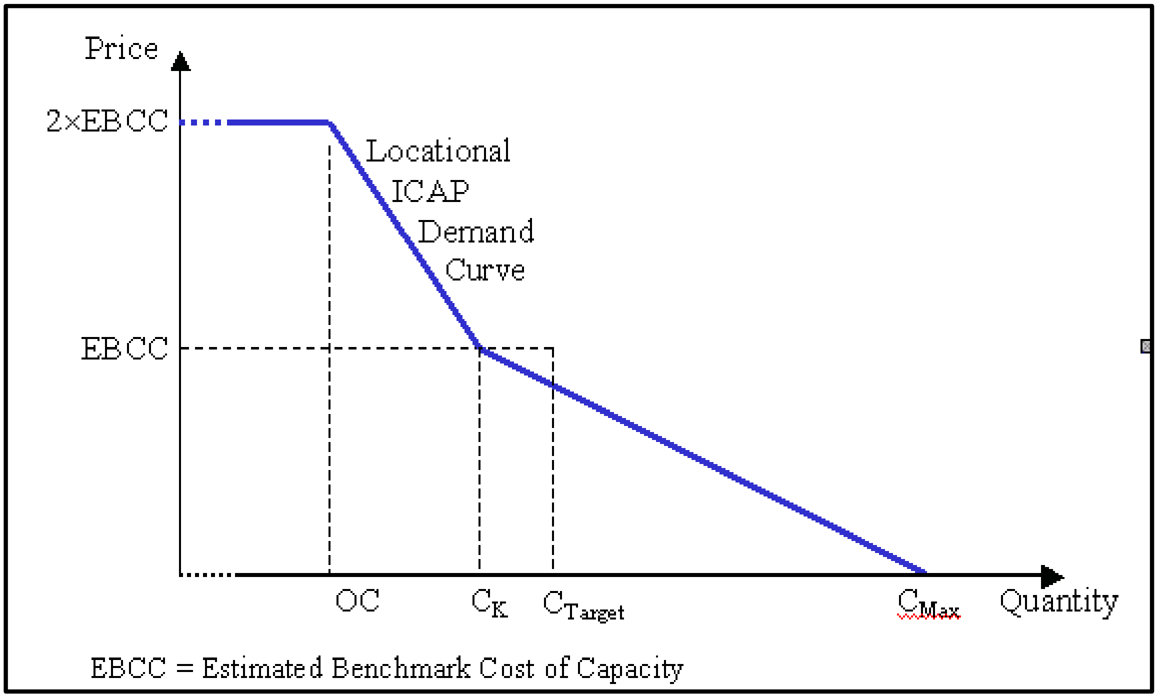
[46] The 1-day in 10-year criteria for NPCC is specified in NPCC's "Basic Criteria for Design and Operation of Interconnected Power Systems, 3.0 Resource Adequacy – Design Criteria."

[47] The highest profits would occur if the curve were vertical.

These considerations affected the ISO-NE's thinking about how to design the New England demand curve. The ISO-NE's proposed demand curve is illustrated in Figure 5.

Figure 5
Proposed ISO-NE Demand Curve



Comparing Figure 4 and Figure 5, each of the parameters of the NY demand curve has a counterpart in the ISO-NE demand curve, but in the New England curve, there are additional parameters, and the parameters are sometimes derived in different ways. There is more apparent complexity, and the design goals of the curve have expanded. The key parameters in the proposed New England curve are:

(1) A more complex statement of the reliability standard. In the ISO-NE proposed curve, there are now three parameters – OC, C_k and C_{Target} -- that are intended to interact in pursuit of a level of investment that will meet the desired reliability standard.

(2) The level of reserves that corresponds to the 1-day in 10-year LOLE criterion is called "objective capability" or "OC" in New England; it is called the "minimum NY CA requirement" in New York.

(3) There is a "kink" in the demand curve. The level of reserves at that point is called C_k, and that level is a few percentage points higher than the reserve margin defined by OC. The purpose of the kink is to split the curve into two parts: on the left side, the slope of the curve is steeper; on the right side, the slope of the curve is flatter, with

the intent to balance different design objectives. The intent on the left is to increase incentives for the market to invest in new capacity when the reserve levels fall below the reliability target; the primary intent on the right is to reduce the risks to investors of slightly overshooting the breakeven point, so that on average, investors are more likely to reach the target reserve level.[48] The placement of C_k thus takes on special importance, because it implies that the value of incremental capacity rises rapidly for levels of capacity less than C_k, while the value of capacity declines slowly for levels of capacity greater than C_k.[49]

(4) The curve also specifies C_{max}, which corresponds to the "zero crossing point" in the NY demand curve. In the NY approach, the zero crossing point is explicitly selected; in the ISO-NE approach, C_{max} is derivative of the slopes around C_k. In other words, the curve's designer uses judgment to decide the ratio of the left side slope to the right side slope, given their respective goals. In this case, the chosen ratio is 3:1, so given these slopes, the slope on the right side of the demand curve defines the zero crossing point at C_{max}.

(5) EBCC represents the estimated break-even point for the capacity (and fixed operating) costs of the benchmark unit. As in NY, the benchmark unit used by the ISO is a frame combustion turbine. Since there would be at least five different LICAP regions, there are five curves based on five different EBCCs, reflecting the different estimates of costs of building a CT in each region.[50]

(6) The next point is the price cap. In the ISO-NE curve, this cap is set at twice the value of EBCC. Setting it at this level (as opposed to 1.5 times EBCC or some other value) appears to have been a matter of judgment, with the designer focused on the desire to send a strong investment signal when capacity levels are below the target level. The price cap level is also sensitive to the other parameters. For example, a lower cap would make the left-side slope flatter and thus reduce incentives to invest when reserve levels are less than the capacity target; to make up for this reduced incentive to build capacity when needed, the designer might change another parameter to

[48] Stoft Direct at 15:17-20; Stoft Rebuttal at 42:22-23.

[49] As noted above, the designer's intent behind the different slopes is to provide stronger investment signals when capacity levels fall below the desired level while reducing investment risks when adding capacity that might exceed the desired level. See, Stoft Direct, at 15:17-20. Dr. Stoft also makes a theoretical argument for this difference in assumed values in Stoft, *Power System Economics Designing Markets for Electricity.* Wiley-IEEE Press, New York City, New York: 2002.

[50] Some generators in the LICAP proceeding argued that the more costly aeroderivative unit, rather than the frame CT, should be used as the benchmark unit in constrained local areas. They argued that aeroderivative units should be the benchmark for small, constrained regions, as they are physically smaller, easier to cite in constrained regions, and may require fewer regulatory approvals than frames, which they propose be used as benchmark technology for larger regions. These parties also assert that using the aeroderivative unit as the benchmark will send more timely and efficient signals to new market entrants in constrained areas. However, the FERC ALJ rejected using these units for the benchmark. Initial Decision at 157-158.

encourage more investment or discourage retirement, such as by moving C_{max} further to the right.[51]

(7) Given the parameters of the price cap (2 X EBCC), OC, C_k and C_{max} (derived from the slope to the right of C_k), it is now possible to draw the ISO-NE proposed demand curve shown in Figure 5.

There is still one parameter, C_{target}, to be defined. This parameter defines the region's target level of reserves, *on average*, given the expected variability of reserves relative to OC over time. This notion recognizes that the region cannot achieve OC – the level of reserves consistent with 1-day in 10-year LOLE criterion – exactly each year. Peak demand will vary and differ from forecasts, and capacity levels will change as new units enter the system and older units retire. In some years the resulting capacity reserve levels will be above OC; in other years the reserve margins will be below OC. The ISO therefore reasoned that knowing the reliability criterion (OC) was not sufficient by itself; the ISO still needed to determine how much, or how often, the level of reserves should fall below OC, because that would affect the placement of the curve. As stated by ISO witness Dave LaPlante,

> "The implementation of a demand curve requires us to develop a standard that addresses changes in load and capacity values from year to year."[52]

The ISO also reasoned that the costs to consumers of falling below OC by a given percentage would be significantly higher than the costs of going above OC by the same percentage. This conclusion is premised on the argument that the economic costs of involuntary curtailments can be very high, while the costs of a little excess generation would add relatively little to overall electricity rates.[53]

To derive C_{target}, the ISO attempted to determine a "regional reliability standard" that it believed would be consistent with the level of reliability historically achieved in the New England region. The ISO examined the available data on reserve levels relative to OC for the previous 21 years (apparently, the only years for which such data were available). Based on this data, the ISO found that reserves have been above OC in most of the years, and below OC in only 3 years, or about 14 percent of the years. A further statistical analysis of the same data showed an approximately normal distribution of capacity around a level of capacity higher than

[51] Stoft Rebuttal at 6:15-21. In the LICAP hearings, parties representing loads tended to urge changes to individual parameters in ways that all resulted in less total investment or lower payments; generator parties tended to change individual parameters in ways that all resulted in more investment and higher payments. According to the ISO, the results were that changes recommended by loads systematically failed to meet the reliability goal, while changes recommended by generators systematically increased likely investment levels far beyond the reliability goal.

[52] LaPlante Rebuttal at 28-30.

[53] Hence the argument concludes that the costs of an increased probability of involuntary rolling blackouts, when falling below OC, is less than the cost of exceeding OC by the same amount. Note that this argument depends somewhat on the assumption that OC itself reflects an economically desirable level of reserves, even though the 1-day in 10-year LOLE criterion is essentially an engineering standard and is not based on estimates of the value of lost load. On the other hand, the ISO might argue that by accepting this criterion for so long, utilities and regulators have implicitly accepted its economic justification.

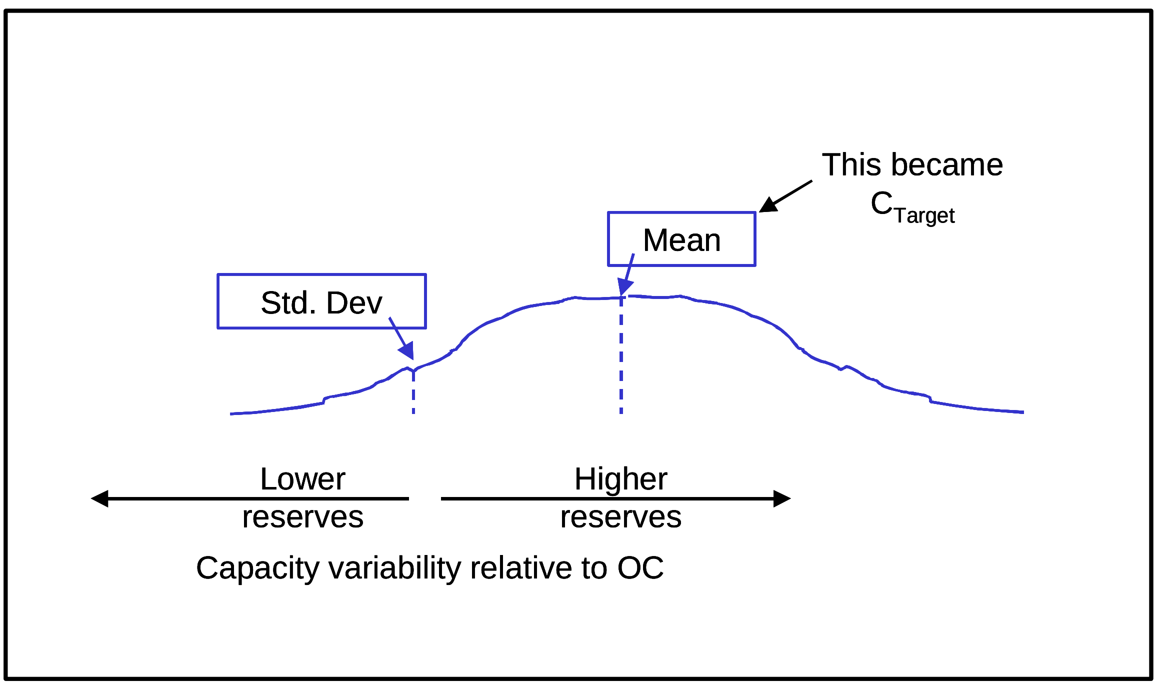
OC. Taking the standard deviation, the ISO argued that to achieve the historic level of reliability, the region should not allow reserves to fall below OC more than 17 percent of the time. It then used this finding to define the average target level of capacity, or C_{target}, which occurs at the mean of the expected distribution.[54]

As described by the Dave LaPlante, capacity variation in the past was distributed around a mean value somewhat higher than OC.

> "The data showed that the average surplus over this period was 105.4% above OC and that the standard deviation of the surplus during that time period was 5.8%. Assuming the distribution of annual capacity surplus to be a normal distribution with a mean of 1.054 and a standard deviation of 0.058, one can expect to be below OC roughly 17 % of the time."[55]

Figure 6 illustrates the concept of the historic variation in capacity levels around a level of capacity higher than OC and the resulting derivation of C_{target}.

Figure 6
Historic Variability of Capacity
Relative to OC

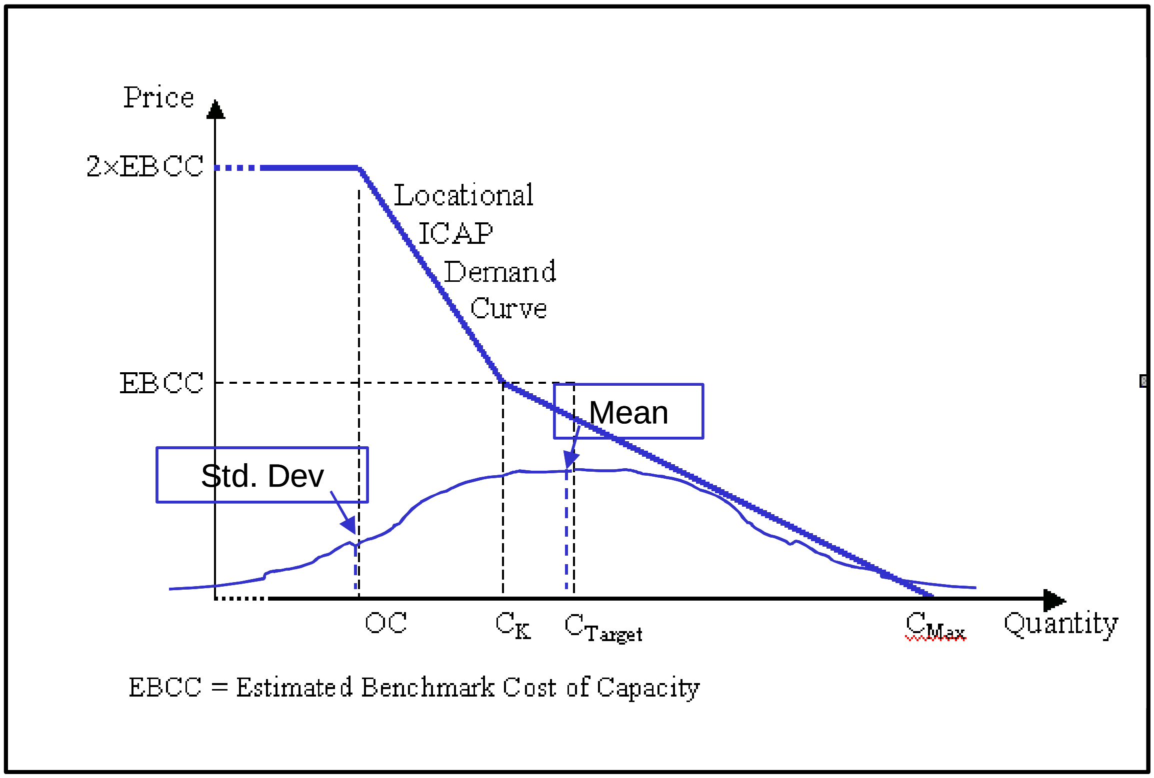


[54] Stoft Direct at 78-79; LaPlante Rebuttal at 34.

[55] LaPlante Rebuttal at 34.

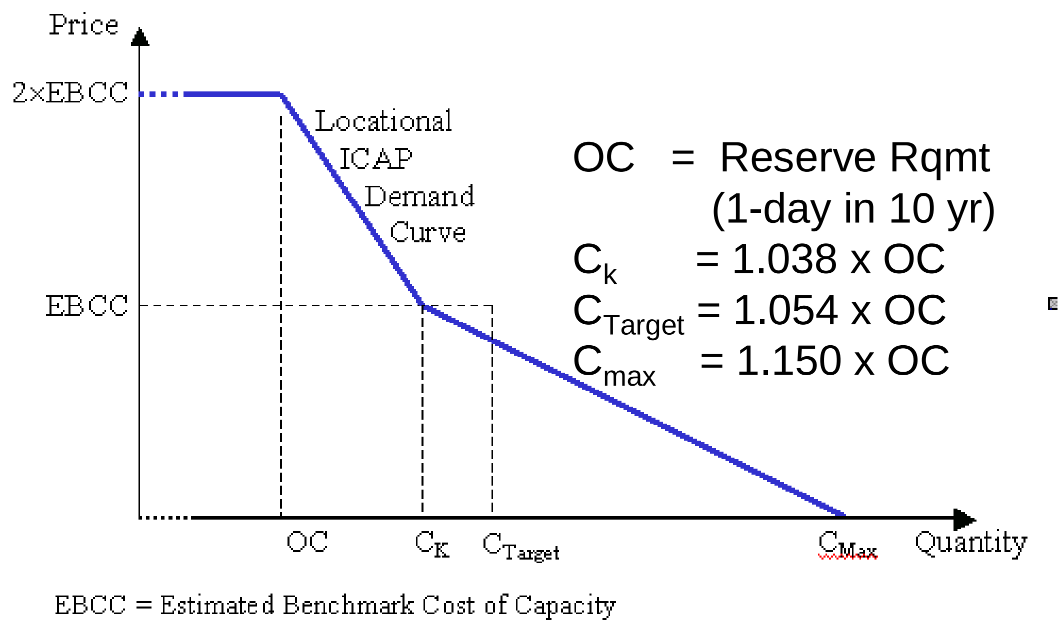
Using this capacity distribution from the past as a guide, the ISO defined the target level for capacity, as shown in Figure 7.

Figure 7
Historic Capacity Variability
Defined C-Target



In this figure, C_{target} is set at the mean defined by the historic distribution. The distribution is then placed at the point where the standard deviation reflected in the historic distribution equals OC. The placement of the curve is thus intended to achieve, on average, the same degree of compliance with the reliability standard as New England has experienced historically. In other words, if the region achieves C_{target} on average, *and* the variability of capacity relative to OC is about the same going forward as in the historic period examined by the ISO, then the region will not only surpass OC on average but it will also not fall below OC reserve levels more than 17 percent of the time. The ISO defined this goal as the "regional reliability standard" for New England. The resulting reserve margins relative to the 1-day in 10-year LOLE criterion are shown in Figure 8.

Figure 8
Reserves Margins above OC
Implied by ISO-NE Curve



Source: Stoft rebuttal, Exh ISO-36:17

Issues Concerning the ISO-NE Demand Curve

The ISO's use of the historic distribution of capacity for the proposed demand curve was premised on the argument that since this was the level of capacity achieved in the past, it could be used to define what the average target should be in the future.[56] The ISO argued that since utilities built this level of capacity and regulators approved this level in the pre-market regulatory regime, there was an implied acceptance of this level as the *de facto* reliability standard for New England. However, in the hearings, New England state regulators and parties representing loads argued against this assumption. These parties also argued that if the demand curve worked as well as the ISO hoped, then the variability of capacity would likely be lower in the future than it had been in past. However, these positions were not accepted by the ALJ in her Initial Decision.

Several parties agreed with Dr. Stoft that the new demand curve could reduce the variability of capacity, in part because the curve's incentive structure would encourage investment and retirement decisions that would move investors closer to OC with less variability than experienced under the prior regulatory and early market regimes. However, Stoft indicated that there was no assurance of this improvement and that in the absence of better empirical

[56] LaPlante Rebuttal at 32-33.

information, the only evidence to go on was historical performance. If actual performance under the curve improved over historic performance, then the standard deviation used to position the curve could be adjusted (moved to the left) in the future (ISO proposed annual updates, although load parties complained that even if observed variability decreased each year, the annual adjustments would be minor each time, because of the ISO's expressed desire to reduce regulatory uncertainty).[57]

The proposal to implement a downward sloping demand curve has general support among generators but virtually no support from parties representing loads in New England or from New England state regulators and public officials.[58] Perceptions about the effect of the demand curve approach on near-term capacity payments (for generators) and the resulting costs (for loads) probably explain these starkly contrasting positions.[59]

Under the current ISO-NE UCAP system, the ICAP price paid to generators in the monthly auctions is determined by a vertical demand curve. When there is even a small surplus of capacity over the reserve requirement, UCAP prices fall to very low levels, close to zero (see Figure 8, above). There is currently a surplus above the reserve requirement for the New England region as a whole.[60] As a result of this regional surplus, current monthly capacity prices throughout New England are very low, and these low spot capacity prices are reflected in low term contract prices (and likely lower demand for such contracts).

Under the ISO-NE's proposed downward sloping demand curve and the values for C_k, ICAP prices in the short run would likely be higher than current levels, although ICAP prices would remain below the estimated break-even point for recovering generators' fixed costs as long as the region was in surplus.[61] Hence, as soon as the ISO-NE proposal was implemented, generators across the region would receive higher ICAP payments, and loads would pay higher prices for capacity for purchases in the monthly ICAP markets. While loads might be hedged against increases in spot capacity prices through existing term contracts for capacity, in the long run one might reasonably expect forward prices and contract renewals to reflect the higher prices

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[57] Stoft Rebuttal at 17-18.

[58] See Appendix B, which summarizes correspondence to FERC opposing LICAP in general, and the demand curve in particular, from New England state regulators, state Attorneys General and most of the New England Congressional delegation.

[59] Substantial opposition to LICAP also came from parties in Southwest Connecticut, who objected to the creation of a SW Connecticut LICAP zone, which they believed would result in higher ICAP payments for loads in that area than for the remainder of Connecticut or New England. Note, however, that the costs of the RMR contracts and costs of any new generation procured under an emergency RFP for that region would also be allocated to loads in the energy load zone containing the constrained region.

[60] While there is a *regional* surplus, there is little if any surplus in transmission constrained areas such as Southwest Connecticut. In such regions, any apparent surplus is maintained by counting units that are under RMR contracts but that might otherwise have retired without such contracts. The imminent need for additional resources in Southwest Connecticut has led to emergency RFPs for new capacity in that area and to accelerated efforts to build new transmission into and within that area.

[61] Current capacity levels are generally higher than C_k.

permitted under the downward sloping demand curve. While the long-run price of ICAP would have to equal the long-run cost of capacity in any case, load parties seemed focused on the short-run effect. It is not surprising, therefore, that load and state opposition to the LICAP approach focused on the prospects for higher near term prices under the proposed demand curve, resulting in requests that FERC deny approval or at least delay implementation for a year or more. These protests have already been partly effective in delaying the ISO's planned implementation date from June 1, 2006 to some yet to be determined date after the 2006 summer season.[62]

There is no dispute that, under current surplus conditions, a downward sloping ICAP curve will increase capacity payments in the near term compared to a vertical demand curve. However, it is not clear how much the total cost to loads would increase even in the short run. In the absence of LICAP and the downward sloping curve, the ISO would still need to provide compensation to plants needed for reliability that might otherwise be retired because of the "missing money" problem. Additional RMR contracts would seem likely, and this is reflected in the substantial increase in the number of RMR requests submitted by generators in recent months.[63] Most of the requests have not yet been decided by FERC. If LICAP and the new demand curve were delayed, it seems likely that more of these requests would be made and approved than would occur once LICAP is implemented. In that event, RMR costs would be allocated to LSEs in the local load zone.

The increased costs attributable to LICAP and the sloping demand curve can also be seen as a transition problem, not a long-term effect. That is, the increased costs reflect a short-run transition from a vertical to a sloped demand curve, but in the long run (a period long enough to allow new investments to occur under either approach), there is no obvious reason to believe that the total cost of capacity supported and encouraged under the sloped curve is greater than the total cost of capacity that would be supported and encouraged in response to the current vertical curve. Indeed, to the extent that the sloped curve reduces investment risks by reducing the volatility and unpredictability of capacity prices associated with a vertical curve (assuming both curves are set to achieve the same equilibrium level of capacity), the ISO can argue that total costs will be lower under its approach than would be the case if the vertical demand curve remained in place. There does not appear to be an empirical way to test these arguments.

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[62] See, e.g., Opening Brief of the New England Conference of Public Utility Commissions (NECPUC Opening Brief); Letter from New England Congressional Delegation to FERC Chairman, July 5, 2005. ISO-NE originally requested a FERC decision on LICAP by mid September 2005, to allow it to implement ICAP by early 2006. However, in response to substantial opposition from New England regulators and public officials, FERC granted a request for oral arguments, now scheduled for September 20, 2005. *Order Granting Oral Argument and Delaying Implementation of Locational Installed Capacity Mechanism* in FERC Docket ER03-563-030 (August 10, 2005 Order). FERC did not set a date for a decision, and this required the ISO to abandon its plans to implement LICAP prior to the summer of 2006. As of this writing, no new date has been set.

[63] LaPlante Rebuttal 4-5, 49, 70, 72. LaPlante suggested that as many as 10,000 MW of capacity might eventually apply for RMR treatment in the absence of the ISO proposal.

Who Speaks for Loads?

The ISO's interpretation and specification of a "regional reliability standard" has created further opposition to the sloped demand curve approach among New England state regulators, officials and parties representing loads. Their principal argument is that the ISO has created a new regional reliability standard by specifying that the region should not fall below OC more than 17 percent of the time. This new standard, they argue, would impose substantial additional costs on New England consumers and would "institutionalize excess capacity that has existed in New England over the past 21 years."[64] These parties appear to accept without question that the regional reliability criterion (OC) is and should be based on the long accepted 1-day in 10-years LOLE criterion. However, they do not support the ISO's further interpretation that the region should achieve that criterion by not falling below it more often than the ISO claims occurred in the past. During the hearings, state regulators and other parties opposing the ISO proposal criticized this interpretation of the "regional reliability standard" on technical grounds, claiming: (1) the historic data is not a sound basis for predicting future variability in capacity relative to OC, because the proposed market will work differently[65] from the prior regulatory regime; (2) even if historic data is relevant, the ISO's choice of data was faulty. In addition, opponents made important policy arguments against the ISO proposal: (1) the states, not the ISO, should have the responsibility for setting the reliability standard and (2), the states have never approved the ISO's interpretation of the regional reliability standard.

These latter arguments raise important issues: In the absence of direct indications from consumers about their willingness to pay to avoid involuntary curtailments, who speaks for consumers? If the design and placement of the demand curve is to be done through administrative means, who has the responsibility to specify how much reliability consumers should be asked to pay for? If the point of the state opposition is that the ISO's demand curve will force consumers to pay for more capacity than consumers should be required to buy, then what level of capacity (how much reliability) are the state rate regulators willing to accept on behalf of consumers?

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[64] See, e.g., Initial Brief of the New England Conference of Public Utility Commissioners (NECPUC Brief); Testimony of Drs. Pechman and Bidwell on behalf of Connecticut DPUC and other Parties, 27, 35-36.

[65] State regulators collectively (as in the NECPUC Brief) took conflicting positions on how well the LICAP/demand curve approach would work. On the one hand, the regulators doubted that the approach would actually induce new investments and expressed concern that it would only provide "windfall profits" to existing plants. On the other hand, when arguing about the parameters of the demand curve, regulators and load parties consistently argued that the variability of capacity in the future under the ISO's curve would be significantly less that what the ISO observed historically. This would then translate to a smaller distribution, and hence smaller standard deviation – the distance between OC and C_{target}. In other words, less variability and a smaller standard deviation would allow the ISO to shift the entire curve to the left, reducing the capacity requirement and thus lowering total costs – the effect the States were hoping to achieve. Applying a smaller standard deviation to the placement of the demand curve would mean that significantly less capacity would be needed than in the past to meet the same average level of reliability. The States' argument thus implies that the ISO market will work quite well, not only in inducing new investment but also in keeping the level of investment fairly close to the desired reliability levels with less over- or under-building. None of the State or load parties has attempted to reconcile these conflicting positions.

Importantly, New England state regulators or public official did not squarely address these questions. Yet state regulatory silence on issues that appear to go directly to their authority to define just and reasonable retail rates may lead to an ironic result: If states within the region fail to specify the reliability standard in meaningful detail, and fail to take responsibility for the resulting costs and reliability levels, then the practical effect may be to leave the ISO proposal as a default, with the ultimate decision made and imposed by FERC.

Defining and Implementing Locational ICAP Markets

The original ISO-NE LICAP proposal would have created four LICAP zones, but in its June 2, 2004 Order, the FERC asked whether an additional zone would be appropriate for Southwest Connecticut. In a subsequent filing, ISO-NE concurred and asked for approval of this fifth zone, which FERC approved.[66] The resulting five zones under the current LICAP proposal are:

(1) Maine, which is recognized as a transmission constrained generation pocket,

(2) The region defined by Northeast Massachusetts (NEMA) and Boston, an area generally recognized as a transmission constrained load pocket,

(3) Connecticut (except for SW Conn.), into which there is limited transmission capacity from the rest of New England,

(4) Southwest Connecticut, into which serious transmission constraints limit the transfer of power even from the rest of Connecticut, and

(5) The rest of the ISO-NE footprint ("rest of pool").

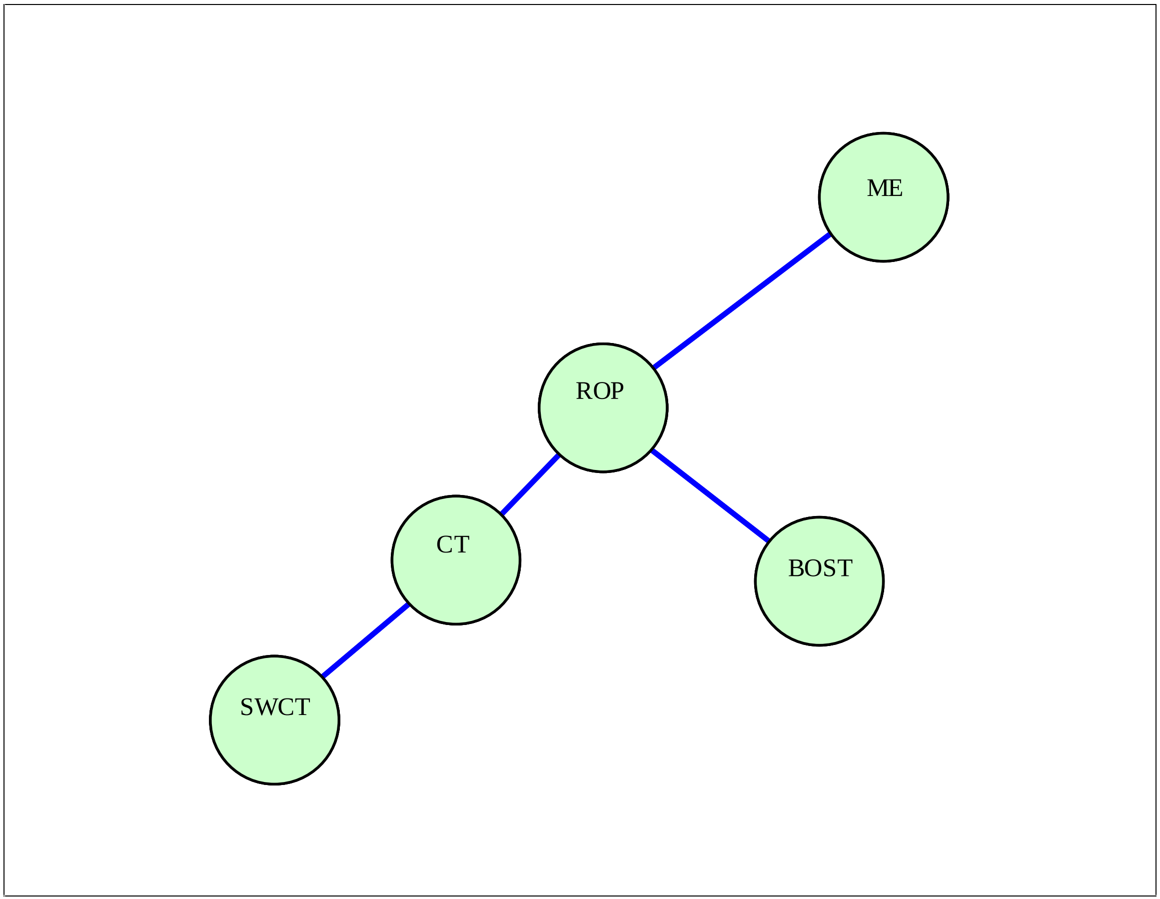
The New England LICAP zones continue the pattern observed in New York, in which the identified zones are amenable to a relatively simplecascading approach when defining local requirements and transfer rights. In New York, the constraints move from "rest of state" to New York City to Long Island in a simple radial fashion. There has been no effort to further differentiate LICAP zones, such as by acknowledging transmission constraints within the New York City or Long Island zones that might further limit the ability of capacity in one part of the zone to meet the reliability requirements of another part of the same zone.

In the ISO-NE proposal, there are five zones proposed for New England instead of three (as in NY), but the zones reflect a view of the New England system in which flows from generators in Maine are limited into the rest of New England, and from there flows are limited into the NEMA/Boston and Connecticut regions and then into Southwest Connecticut. The zones thus line up in an essentially radial configuration that appears to avoid the need to examine simultaneous transfer limits into the same zone from multiple abutting zones. It is not clear whether this accurately reflects the actual grid configuration or is instead a deliberate design

[66] *Order on Compliance Filing* 109 FERC ¶ 61,156 (November 8, 2004 Compliance Filing Order)

constraint imposed in the hope of keeping market implementation easier. These questions are not addressed in the ISO proposal. The apparent configuration of the ISO-NE zones is shown in Figure 9.

Figure 9
Locational ICAP Regions and Transmission Interfaces



This figure, from Dave LaPlante's Direct Testimony of August 31, 2004, page 30, does not indicated whether the interfaces between zones have directional interface limits with different limits in each direction. The drawing indicates a radial system, but it does not describe how New England relates to New York or other systems.

When examining the effectiveness of a LICAP approach, an important question is whether a limited number of LICAP zones can effectively solve the "missing money" and "missing incentive" problems accurately enough to effectively reduce the need for RMR-type solutions. The energy markets settle each generator at its nodal LMP, and price mitigation rules may have different effects at different locations. The use of a few LICAP zones may only partly address the missing money problem, leaving many locations within a zone in which the combined compensation from the nodal energy market and the zonal LICAP market provides neither the right incentives for investments at those locations nor the right incentives for operational decisions that encourage availability.

As observed in *energy* markets (e.g., California) where settlements are done on a zonal basis, there can be constraints within each zone that would warrant different locational prices, hence the need for LMP. When that occurs, the use of zonal energy prices can create perverse incentives that are reflected in both investment and operational decisions inconsistent with the need for reliability. The same concerns would appear to apply if ICAP payments are based on large LICAP zones if the zones do not accurately reflect the actual constraints on the ability to move power from one region to another. This suggests that while LICAP may be an improvement over a regionally uniform ICAP payment regime, it may not eliminate the need for additional compensation schemes for selected generators at selected locations important for reliability. RMR-type contracts would likely still be needed at specific locations within a LICAP zone, and the extent of their use would depend in some part on how well the LICAP zones accurately reflect the actual constraints that limit the deliverability of power on the grid.

A further implication of the limits of the LICAP zonal approach is that the ISO may find it politically difficult to redraw zonal boundaries or create new LICAP zones if it finds that constraints within an existing zone are forcing too much reliance on RMR type solutions to compensate units needed for local reliability. In Connecticut, the ISO-NE has experienced considerable public opposition from many local officials and customer groups objecting to the creation of a separate Southwest Connecticut zone, and this in turn has helped undermine support for the overall LICAP proposal from state officials.

The judgments involved in setting and enforcing the transmission constraints applied in the reliability calculations can only approximate the limits imposed by the physical system used for actual operations. Constraints within the zones influence the calculation of the Capacity Transfer Limits between zones. Hence, it is not a straightforward matter to set the criteria and define the zones. The choices affect both reliability and the transfer of significant payments among the parties.

Transmission capacity

In the ISO-NE LICAP proposal, transmission capacity is explicitly defined as the difference in the total capacity requirement for a LICAP Region (zone) and the amount of that requirement that must be satisfied by capacity resources located in that LICAP Region. Each year the ISO would determine a LICAP Region's requirements in proportion to that Region's share of the New England Control Area coincident peak from the previous year.[67]

For each LICAP Region, the ISO would conduct a reliability study to determine the portion of that Region's capacity requirement that must be provided from resources located within that Region. The Capacity Transfer Limit or CTL determined for each LICAP Region represents a

[67] Direct Testimony of Mark Karl at 4-5. See also Karl Rebuttal at 4-5.

constraint on the ability to import capacity to meet capacity requirement in the Region or Regions on the import side of that constraint.

The Capacity Transfer Limits determined by the ISO-NE allow for modeling nested LICAP Regions and export constrained LICAP regions. In particular, the New England LICAP market models Southwest Connecticut LICAP Region as import constrained within the Connecticut LICAP Region, which in turn is import constrained from the rest of the pool. It also models Maine as a LICAP Region that is export constrained from the rest of the pool.[68]

Transmission rights

The ISO-NE proposal would explicitly define transmission rights. For each LICAP interface the total quantity of available Capacity Transfer Rights (CTR) is equal to the Capacity Transfer Limit (CTL) for that interface. These rights are financial; they pay the holder the difference in Locational ICAP prices between the two LICAP Regions associated with CTR.[69]

All resources purchased in a LICAP Region are paid the local clearing price and all LSEs are charged the local clearing price for all capacity purchased on their behalf. This settlement creates an over-collection of revenues by the ISO-NE, since the LSEs in import constrained LICAP Regions are charged the local clearing price for both local and imported capacity, while only local capacity receives this price. The role of CTRs in the settlement process is to allocate the over-collection of revenue to market participants that use the interfaces.

The ISO-NE deferred to the Commission how best to allocate the CTRs. According to Mr. Karl, the ISO was willing to consider accommodating a preferential allocation of the ability to import into, and export from constrained LICAP Regions following requests from market participants. Such requests might be based on past interconnection status of individual resources.[70] For example, in its original March 1, 2004 filing, the ISO suggested that CTRs on the Maine export constraint could be allocated to generators in Maine, allowing them to receive the price in import constrained LICAP Regions for capacity they provide in Maine that is exported to constrained LICAP Regions. In his later direct testimony, Mr. Karl suggested allocating CTRs associated with each constraint proportionally to all market participants serving the load on the import side of the constraint, reasoning that these are the entities that "ultimately pay the costs of the transmission system."[71]

The ISO-NE proposal to allocate the CTRs over each import and export constraint proportionally to the load served behind that constraint could be applied to the case of nested LICAP Regions. In particular, the example Mr. Karl provides in his direct testimony suggests that an LSE serving load in Southwest Connecticut would receive a share of the CTRs over the SWCT import constraint proportional to its load served within the SWCT LICAP Region. It would also receive

[68] Mark Karl Direct at 5.

[69] Mark Karl Direct at 3.

[70] Id. at 13.

[71] Id. at 26.

a share of CTRs over the Connecticut import constraint proportional to its load served within Connecticut LICAP Region. Finally, this LSE would receive a share of the CTRs over the Maine export constraint proportional to its load served on the import side of that constraint. Table 1 shows the example offered by Mr. Karl of distribution of CTRs across LSEs serving load within LICAP Regions of the ISO-NE.

Table 1: CTR allocation to LSEs in Locational ICAP Regions

	Percentage of CTRs allocated				
	Total Locational ICAP Obligation (MW)	SWCT CTRs	CT CTRs	NEMA CTRs	Maine CTRs
SWCT	4108	100.00%	51.78%		15.14%
Northern CT	3826		48.22%		14.10%
NEMA/Boston	5806			100.00%	21.40%
Rest of Pool	13394				49.36%
Maine	2232				
Total	29366	100.00%	100.00%	100.00%	100.00%

Source: Direct Testimony of Mark Karl at 22.

Using a Reserve Shortage Hour Availability Metric

The ISO-NE describes its proposal to use a reserve shortage hour metric to replace the current UCAP availability mechanism as an essential component of the overall proposal. Steve Stoft testified that he could not support the LICAP proposal if it did not include the reserve shortage hour metric.[72] While this feature of the proposal has strong support from most if not all of the state regulators and parties representing loads, it faces almost universal opposition from generators. In her Initial Decision (ID) issued in the LICAP proceeding on June 15, 2005, the ALR *rejected* the reserve shortage hours metric, finding that it was not sufficiently developed by the ISO and expressing concerns that it was not consistent with the availability metric (UCAP) used by PJM or New York.

Recall that a central purpose of the reserve shortage hour proposal is to ensure that generators that receive capacity payments are actually available to provide energy and/or operating reserves in those hours in which the system is most stressed and capacity is most valuable. Making ICAP payments depend on availability during these stressed hours was intended first to overcome two concerns with the UCAP approach: (1) the reserve shortage hour approach replaces the UCAP system that measured availability on an average basis, which ignores the fact that capacity has more value to the system in shortage hours than in non-shortage hours, and (2) it substantially reduces the degree to which a unit's score for availability depends on self reporting. It may also eliminate the need for a separate set of administrative penalties for non-performance when generators fail to meet their ICAP obligations.

The reserve shortage hour approach is intended to reward generators that contribute to reliability when capacity is most valuable, and avoids making (or reduces) capacity payments to generators that do not contribute to reliability when their capacity is most needed. This aspect of the proposal is particularly important to loads, who are concerned about the prospects of making higher capacity payments (during a transition or surplus condition) under the downward sloping demand curve than under the current system. From their perspective, if they have to pay more for capacity (in the short run), they want to make sure they are getting the reliability they are presumably paying for.

For the ISO, moreover, there was a second and equally important reason to change to a reserve shortage hour approach. The ISO-NE had experienced periods of reserve shortages and come close to rotating blackouts on past occasions, most recently during a previous winter. During that winter, some generators declared themselves unavailable for economic reasons when the region experienced a severe cold snap and associated price spikes and near shortages in the natural gas market. Some generators sold their gas back to the market, where its value was presumably higher than their own use.[73] One of the lessons that could be drawn from this

[72] Stoft Rebuttal at 2.

[73] *Final Report on Electricity Supply Conditions in New England During the January 14-16, 2004 "Cold Snap"* P. 72. Published by ISO New England Inc. Market Monitoring Department. October 12, 2004. Available at http://www.iso-ne.com/pubs/spcl_rpts/2004/cld_snp_rpt/1_Final_Report_On_January_2004_Cold_Snap.pdf

experience was that generators were unlikely to take a variety of steps necessary to ensure electric generation availability, given the incentives provided by the UCAP approach. Yet it was unclear which steps generators should have taken: Should they have bought sufficient gas in advance? Should they have maintained gas storage? Should they have invested in dual-fuel capabilities? And should the ISO define these steps and mandate them as a prerequisite for meeting ICAP eligibility, or should the ISO change the incentives to reward those units that were actually available, and let the market sort out which of these actions made the most sense? ISO-NE chose the latter approach – change the incentives – in the belief that the market would do a better job in sorting out the right mix of investment and operating practices.

The ISO-NE's market incentive approach became an explicit ISO goal in the LICAP proceedings. The ISO-NE witness, Dr. Stoft, argued that the overall design of the LICAP markets was guided by the desire to mimic, wherever possible, the market incentives that would be provided by an "energy-only" market structure. Stoft reasoned that under an energy-only market structure (without explicit price caps and no ICAP markets or payments), generators would respond appropriately to the market price incentives of the uncapped energy market. They would decide which investments and operational practices would be worth pursuing to ensure that they received high energy prices when near shortages occurred and prices were highest. During periods of reserve shortages, energy and operating reserve prices would rise toward shortage-cost levels, and it would be these hours in which generators could expect to recover a large portion of their fixed costs and expected profits, *but in an energy-only market, only generators who were operating (or providing operating reserves) during those hours would actually receive these prices*. It followed that if the ICAP markets were to provide the missing money resulting from energy market price caps, then to mimic the incentives of the energy-only market, the payments for ICAP should be made for essentially the same performance that would have earned the shortage-cost energy prices in the energy-only markets. ICAP payments should therefore be made to generators that provided energy and/or operating reserves during reserve shortage hours (which would presumably be about the same hours in which energy price caps would likely be triggered); and conversely, generators that failed to be available – failed to provide energy and/or operating reserves – during these critical hours should not receive ICAP payments (or should have their levelized ICAP payments correspondingly reduced), because they would not have received the high energy prices in the energy-only market.

Most of the New England generator's arguments against the reserve shortage hour metric were based on the idea that it would be unfair to financially penalize a generator if it were unavailable for reasons outside the generator's control.[74] In addition, generators claimed that the approach was untried and inconsistent with the metric used in New York, and if different from New York, the New England approach might pose a barrier for inter-regional ICAP trading.[75] The ISO responded to these concerns, arguing that in an energy-only market, generators might also be unavailable for a variety of reasons but, according to the ISO, no one would argue that in an energy-only market generators should be paid for energy or operating reserves they did not

[74] *Joint Initial Brief on Availability Criteria of the Capacity Suppliers and Con Edison Energy*. FERC Docket ER03-563-030. April 15, 2005 (Capacity Suppliers) at 17.

[75] Initial Decision at 207.

provide.[76] Otherwise, the ISO argued, the approach would resemble a cost-of-service approach and not a market-based approach. The ISO also offered to continue calculating the UCAP value for units based in New England that sought to sell capacity to New York (as well calculating the availability rating based on reserve shortage hours), thus reducing concerns about inter-regional trading barriers.[77] In her ID, however, the ALJ concluded that while the approach was "promising," the Commission should reject the ISO-NE proposal at this time because of its novelty and the fact the ISO had not addressed every possible concern offered by the generators.[78]

ICAP Payments Under the Reserve Shortage Hour Metric

If, notwithstanding the ID, the Commission approves the reserve shortage hour metric, the proposal would affect how generators are paid for ICAP. The ISO proposes that ICAP payments paid to a generator each month be adjusted by an availability factor (A_g) that reflects that unit's availability during all previous reserve shortage hours during the prior month.

If the new metric is implemented, each generator will begin with its then current UCAP rating. Thereafter, each generator's availability factor will be adjusted after each shortage hour to reflect whether or not it was available during any shortage hour(s) during that month. The new data for each shortage hour is then blended with the previously determined availability factor to derive the new availability factor. After this adjustment process is made in sequence for each shortage hour, the resulting availability factor is used to determine payments in the next month's auction.

$$\text{New } A_g = (.95 * \text{Old } A_g) + (0.05 * A_{hg})$$

Where:
Old Ag = the availability factor for that unit from the last Ag calculation
Ahg = whether the unit was or was not available during the shortage hour since the last Ag calculation[79]

The resulting Ag at the end of the month is then applied for the next month's LICAP payment. Applying the formula, if there was a single shortage hour during the month, and the unit was available during that hour, the unit's availability factor would increase by 5 percent over the previous month; if the unit were not available during that shortage hour, the factor would decrease by 5 percent from the previous month. A separate adjustment would be made for each

[76] Stoft Rebuttal at 119:5-11.

[77] Mark Karl Rebuttal at 24.

[78] Initial Decision at 203-206.

[79] LaPlante Rebuttal at 86. The "measure" referred to here has not been fully defined by the ISO. In the simplest terms, it appears that the measure would be either "was available = 1.0" or "wasn't available = 0.0". It is not clear whether a unit that was partially available (for part of an hour or for partial capacity) would receive a partial or proportional score.

shortage hour during the month, in sequence. Thus, if there were two shortage hours during the month, the availability factor coming into the month would first be adjusted for the first hour, and then the resulting availability factor would be adjusted for the second hour. If no shortage hours occurred during the prior month, there would be no adjustment for the next month, and the availability factor from the previous month would carry over.[80]

During the LICAP hearings, generators pointed out that a unit starting with a relatively high factor, such as .90, would find that if they missed a single shortage hour and had their factor lowered by 5 percent (to .855), it would take many shortage hours without missing to make up for the effect of the one hour they missed; this might take many months if there were few or no shortage hours for several consecutive months, but the reduced payments would apply throughout that period. While this is mathematically correct, the ISO argued that this was reasonable because it reinforced the desired incentive for generators to take all steps necessary to ensure availability during shortage hours.[81]

The ISO describes its reserve shortage hour approach as "flat and simple," in contrast to an earlier version of a proposed availability metric.[82] The earlier version focused on "critical hours" rather than reserve shortage hours. The original concept was to have the ISO identify which hours were "critical" to reliability, and then assign a weight to each hour, depending on the value of capacity in each hour relative to how critical the hour was. Payment adjustments to generators would then depend on which critical hour they missed and the relative weight of that hour. Under this earlier proposal, there might be as many as 200 critical hours in a year.[83]

Generator parties noted that the ISO had not clarified the criteria either for defining critical hours in advance or assigning the weights for each critical hour. Rather than refine this approach further for the hearings, in its rebuttal testimony, the ISO replaced the critical hours approach with its reserve shortage hour proposal. The "flat and simple" reserve shortage hours approach treats all shortage hours the same: that is, capacity is valued the same in an hour whether the operating reserves fall to 5 percent or 3 percent.[84]

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[80] Initial Decision at 87.

[81] *Errata to Reply Brief of ISO New England, Inc.* in FERC Docket ER03-563-030. April 27, 2005. (ISO Reply Brief) at 83.

[82] LaPlante Rebuttal at 83.

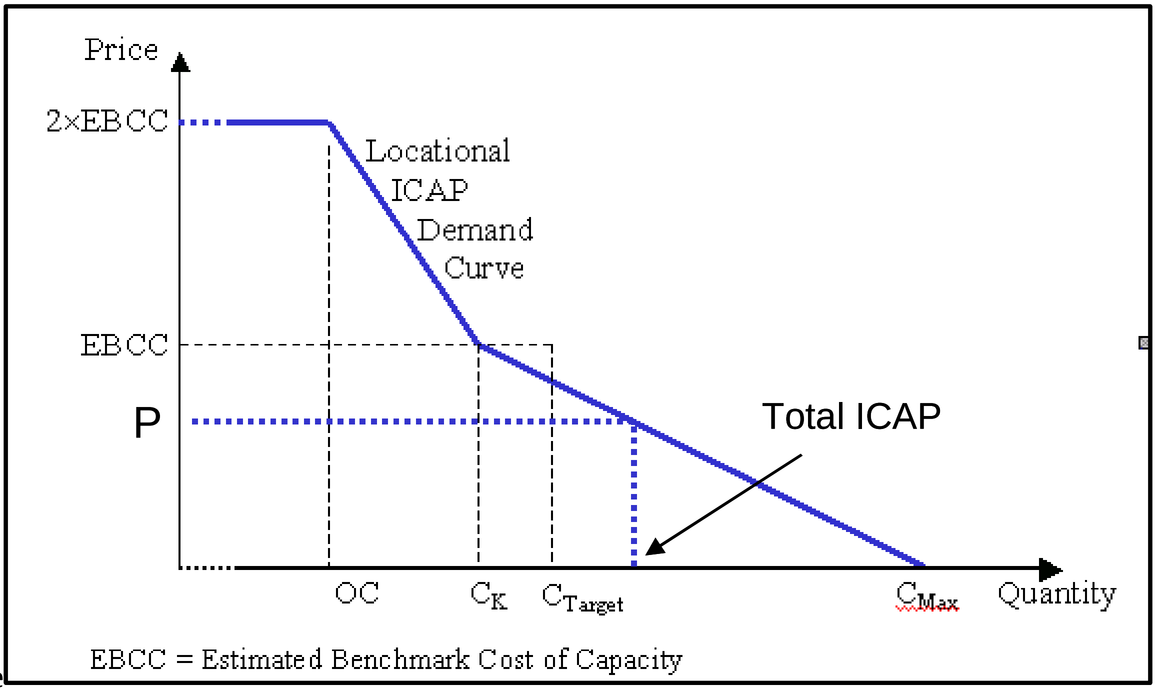
[83] On the original "critical hours" proposal, see Stoft Direct at 24-27; on the reasons for changing to the "flat and simple" shortage hours approach, see LaPlante Rebuttal at 14-15. For example, generators noted that the critical hours and their weighting would not be known in advance; some critical hours might be similar to non-critical hours; generators would find it hard to guess which hours would be critical and might be induced to self schedule their units uneconomically, thus distorting the energy market. Initial Decision at 78-79.

[84] Compare with the NY ISO approach of increasing operating reserve prices depending on how far the ISO falls below the operating reserve target. See, Harvey, "ICAP Systems" at pages 55-57.

Market Power Mitigation and the LICAP Payment Approach

The principal market power mitigation feature proposed by the ISO-NE would count all capacity in the region as "supply" and use that total number to derive the price for ICAP in the monthly auction. The price would thus be taken directly from the downward sloping demand curve and would not be affected by whether or not generators submitted offers for their capacity or by the prices offered by those generators. The intent was to make it difficult for generators to succeed in either physical withholding or economic withholding to raise prices.[85] The basic approach is shown in Figure 10.

Figure 10
ICAP Prices Set by Demand Curve



Re

For puposes of setting the monthly ICAP price, the ISO proposal would count capacity even if it were mothballed. The ISO reasoned that even though a plant might be mothballed in the short run, the capacity could within a reasonable period (a month or so) be reactivated and made available in the event that the owner could foresee monthly capacity prices rising to levels that would warrant reactivation. Since the demand curve mechanism was designed to affect long-run investment in new capacity or long-run decisions to retire capacity, the ISO argued that until a unit was retired,[86] it could be made available to meet New England long run reliability

[85] *Prepared Supplemental Direct Testimony of Steven E. Stoft on Behalf of ISO New England Inc*,, ERC Docket ER03-563-030, November 4, 2004 (Stoft Supplemental) at 4-6.

[86] If a unit's retirement were announced, that unit would no longer be counted toward setting the LICAP price. If the owner decided to bring such a unit back in to operation, it would not be allowed to receive capacity payments for three years. LaPlante Rebuttal at 108.

targets. Until its announced retirement, therefore, the unit would be counted towards the total capacity available to the region for purposes of setting the monthly ICAP price. However, if a unit remained mothballed for three years, it would no longer be counted. [87]

How are Exports and Imports Counted?

The total supply of installed capacity can be affected by net imports and exports. With respect to imports, ISO-NE proposed to count their capacity when defining the price. At the same time, the ISO-NE proposed to subtract exports from New England (e.g., capacity sales to New York) in defining the total capacity that defines price. With respect to exports, however, the ISO acknowledged that owners of substantial generation might be tempted to export some of theircapacity to New York when it was not economic to do so, which would have the effect of "withholding" capacity from the New England market and raising New England ICAP prices that would be paid to the owner's remaining capacity. To discourage this strategy, the ISO proposed to compare expected (or current) capacity prices in the two markets, with the comparison based on UCAP values. If the ISO determined that a sale of capacity into New York was uneconomic (i.e., had a significant negative margin beyond some safe harbor dead band) the ISO would reduce the New England capacity price that applied to any remaining New England capacity owned by *that* capacity owner, but not to the capacity owned all other capacity owners. In that way, the owner that was presumed to be withholding capacity via an uneconomic export would not receive the profits from the increased New England prices caused by the export. The ISO assumed this would be enough to discourage such withholding.[88]

LICAP Payment Reduction for Peak Energy Rentals (PER)

ICAP payments to generators are determined by the ISO-NE demand curve for any given level of total (operating and mothballed) capacity. The ICAP payments for each operating unit whose capacity cleared the monthly auction are then adjusted by subtracting the calculated energy profits –Peak Energy Rentals – that would have been earned by the hypothetical benchmark generator in the ISO's real-time energy markets. Payments for each generator are then further adjusted by that unit's availability factor (Ag). The payment calculation can be illustrated as:

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[87] LaPlante Rebuttal, at 16; Stoft Rebuttal at 141.

[88] Mark Karl Rebuttal at 74-75. For exports from New England to New York, the New England generator is provided with a UCAP rating, which is utilized by New York in its capacity market The UCAP rating is multiplied by the clearing price in the New York zone in which the export is to be delivered to determine gross revenue from the transaction. Net revenue is calculated as gross revenue less the internal New England LICAP congestion charge, equal to the ICAP value of the transaction multiplied by any positive price differential between the New England source and sink zones. The net revenue is compared to the calculated value of the transaction in New England. This value is calculated as the ICAP value of the transaction multiplied by the previous month's LICAP price for the zone in which the generator is located, less the calculated energy market revenue of the applicable benchmark generator. The result is multiplied by the shortage-hour availability statistic to obtain the transaction's value in New England. If the net revenue from New York is greater than or equal to the calculated value in New England, the transaction is considered economic. If the transaction is uneconomic, it will not be denied, but the capacity will continue to count as available capacity in its original zone. Karl Rebuttal at 35-36.

$$\text{Payment} = MW_{ICAP} * Ag * (\text{LICAP price} - PER)$$[89]

Where,
Ag = the availability factor for that unit's capacity, for the auction month
LICAP price = that month's price of capacity from the LICAP zone's demand curve
PER = Peak energy rentals of the benchmark unit, averaged over the 12 previous months

Subtraction of the peak energy rentals is required to ensure that the total payments made to a generator similar to the hypothetical generator would not pay twice for the profits the unit could have made in the energy markets. This is, in keeping with the underlying concept that the ICAP payment is intended to provide the "missing money" resulting from the imposition of caps or other limits on the energy market prices.[90]

The PER is calculated based on actual energy prices in the ISO's real-time spot market.[91] The ISO argued that this would provide a better representation of the likely profits from a peaking unit like the benchmark unit than reliance on day-ahead prices. The PER reduction for any month would be the rolling average of the calculated PER for the previous 12 months (N-13 through N-2) and would be determined before each monthly auction. Generators would thus know in advance of the auction what the PER adjustment would be for that auction month.[92]

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[89] LaPlante Rebuttal at 85.

[90] Initial Brief of ISO New England at 47. There is an unresolved issue about whether the PER reduction approach should also apply to profits that the benchmark unit might earn in markets other than energy. The ISO did not make a proposal on this issue, but load parties argued that the PER rationale should apply to revenues for all markets in which the generators are compensated. The ID agreed in principle, but also agreed with the ISO that there was insufficient evidence on what these other markets might be to include a provision to address their rentals at this time. Initial Decision at 156

[91] In the ISO-NE approach, the rentals are determined by the difference between the actual spot prices in the real-time energy market and a hypothetical competitive price, defined as the variable costs of the benchmark unit. The ISO uses a frame gas-turbine generator as the benchmark unit, with an assumed availability factor or 90 percent, which Stoft notes has the highest variable costs of any economically efficient unit. As a result, Stoft says, inframarginal rentals are the smallest and most accurately estimated in dollar terms, thus insuring the most accurate LICAP payments. For fuel prices, the ISO proposes to use a volume-weighted average of three city-gate prices. These are day-ahead prices, which the ISO recognizes as not ideal. However, the ISO would also adjust the benchmark variable cost estimates by a bias factor, which is the result of comparing the model-predicted PER for actual units in the market to actual revenue derived by those units in the market. Thus, if the model were found to over predict PER by 20 percent, then the bias factor would be 0.8333 (the result of 1/1.20). The bias factor is meant to correct for any systemic bias in the calculation of PER. Some of these details are still under development. E-mail from Mark Karl. The profits earned by the benchmark unit would also vary from zone to zone, based in locational energy prices applicable to the benchmark unit. Stoft Direct at 11-12, 19-20.

[92] LaPlante Rebuttal at 84-85; Initial Brief, at 47-48.

Could The PER Reduction Result in Negative ICAP Payments?

During the hearings, parties noted that the PER reduction could be larger than the ICAP payment for some months, which would suggest a negative payment for capacity in that month. This issue arose primarily because under its original proposal, the ISO would have calculated the PER for each month and applied that month's PER to adjust that month's LICAP payments. This meant that the PER adjustment might be somewhat volatile, with peak unit profits higher in some months of high peak usage but minimal or zero in other months. During months with very high peak profits, the PER could be higher than the unadjusted monthly LICAP price. Initially, the ISO proposed a balancing account approach to avoid negative payments, but this approach was replaced.

In its Rebuttal testimony, the ISO changed its proposal so that PER would be calculated as the average of the previous 12 months, which would presumably flatten the PER adjustments (hence the terms "flat and simple" approach) and reduce the likelihood that the PER in any month would exceed the LICAP prices. With this change, the ISO proposal does not allow for negative payments. If the PER adjustment is greater than the LICAP price, the payment is zero.[93]

Does the PER Reduction Mitigate Market Power in the Spot Energy Market?

Earlier ISO descriptions of the PER reduction suggested that it might also serve to mitigate prices in the *energy* markets. The argument at the time was that if generators knew that their ICAP payments would be reduced by profits achieved in the energy market by the hypothetical peaking unit, there would be a reduced incentive to drive up prices in the energy market, since this would raise the PER calculated for the benchmark unit, which would then be deducted from ICAP payments.[94]

However, it appears that much of the strength of this argument rested on the original proposal to calculate the PER adjustment monthly, after the fact, and then make that month's PER adjustment to that month's LICAP payment. Thus, there would be a reasonably direct correlation between higher prices from market power in any given month and PER adjustments in that month.[95] When the ISO changed its PER approach to calculate the average PER for the previous 12 months, this direct month-to-month connection was broken. Nevertheless, the ISO-NE still claims that the PER adjustment will significantly discourage the exercise of market

[93] LaPlante Rebuttal at 84-85. However, the ALJ concluded that a potential concern for negative payments still remained. The Initial Decision directs the ISO-NE to propose a solution to this possibility. Initial Decision at 156.

[94] Stoft Direct at 19, 22.

[95] A much stronger correlation would occur if the PER were calculated for each shortage hour and applied against capacity payments made on an hourly basis. In that event, the Benchmark generator could not keep the rents it earned, because they would be subtracted from the LICAP payments, so market power would be fully mitigated. When the PER is calculated monthly, and then averaged over 12 preceding months before defining the amount to be subtracted from the LICAP payment, any mitigating effect with respect to market power would appear to be greatly attenuated.

power in the energy spot markets, because the PER deduction, while not immediate, is spread out over the year. However, it notes that, in theory, a generator could exercise market power in the energy market and then "leave the market for the next year, either to export or to retire," although this might rarely occur.[96]

Is the ISO-NE LICAP Proposal a "Market?"

The support or opposition to the ISO-NE pricing mechanism mirrors that found for the proposal to use reserve shortage hours as the availability metric: load parties and state regulators strongly support the pricing mechanism approach to market power; generators strongly oppose it. Most generators argued that mothballed or "delisted" units should not be counted towards the total. They also argued that the ICAP auction price should be set by the intersection of the demand curve and a supply curve defined by the ICAP suppliers' price offers. Otherwise, they argued, the pricing mechanism was not a "market" but was merely an administrative mechanism to determine a capacity payment.

These concerns echo other comments that suggest that the overall demand curve approach is administrative and therefore not a market-based approach, as required by FERC. These comments appear to be half correct. On the one hand, there is no dispute that the demand curve is entirely derived through an administrative process. That is the consequence of the threshold decision not to rely on consumer responses to high prices in an uncapped energy-only market structure. Given this decision, all aspects of the "demand curve" must be administratively derived. However, it does not follow that supply-side responses to the administrative demand curve are not "market based." Stoft argued that even if the demand curve is administrative, and it defines prices without regard to supply offer prices, the supply side is still left free to decide how it will respond to those prices defined by the demand curve. Investors can invest to build new or sustain existing capacity or not; they can decide to retire existing plant or not, and they can decide where and how to allocate their investment, maintenance and operational dollars in response to the price incentives arising from the demand curve payments and the availability metric. Indeed, in defining the reserve shortage hours availability metric, the ISO has chosen an approach that leaves these key decisions to the market, rather than trying to direct the market where to put its focus and money.

The ISO might therefore claim that its approach is at least "half a market." It uses administrative approaches where, as the ISO would claim, it was given no other choice, but it uses market-based approaches where that choice was available.

[96] LaPlante Rebuttal at 87-88.

PJM'S RELIABILITY PRICING MODEL (RPM)

PJM's Reliability Pricing Model, or RPM, has been under development for more than a year. The basic approach was summarized in a November 2004 "White Paper" prepared by PJM for stakeholder comment.[97] Since then, there have been numerous stakeholder forums sponsored by PJM to discuss the merits and refine the proposal, and interaction with the PJM Board, as well as a FERC-sponsored technical conference held on June 16, 2005. PJM and its Board have sought stakeholder support for its RPM proposal, but so far the proposal has failed to achieve even majority support from the PJM Members Committee.[98] Nevertheless, PJM filed its RPM proposal at FERC on August 31, 2005.[99]

PJM's Reliability Pricing Model contains several common elements with the New York markets and the ISO-NE proposal, plus additional elements that expand the scope, purpose and complexity of the RPM. The most notable difference is the PJM proposal to hold a resource adequacy auction four years prior to a delivery year (Base Auction), plus three other supplemental forward auctions between the Base Auction and the Delivery Year as the primary mechanisms to acquire adequate resources. In these forward auctions, new generation capacity would compete against existing capacity, while merchant transmission upgrades and demand-side proposals would also be allowed to compete. The major features of the PJM RPM proposal include:

1. *PJM would use forward auctions for capacity products to be delivered four years later; the four-year forward commitment period is intended to allow new entry and competition from transmission and/or demand response measures*.

2. *PJM would identify specific generator features that would be rewarded with higher prices in the LICAP auctions*.

3. *PJM's RPM structure would be locational, with two zones initially and more zones later*.

4. *PJM auctions would use downward sloping "variable resource requirement" (demand) curves*.

5. *Auctions prices would be determined from the intersection of supply and demand curves*.

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[97] PJM, *Whitepaper on Future PJM Capacity Adequacy Construct: The Reliability Pricing Model*, November 2004, available at http://www.pjm.com/committees/working-groups/pjmramwg/downloads/20050110-rpm-whitepaper-formatted.pdf

[98] See, Letter of Phil Harris to the PJM Members Committee and Stakeholders, March 22, 2005, available at http://www.pjm.com/committees/members/downloads/ltr-to-mc-stakeholders-replaces-311560.pdf.

An initial vote was held by the PJM Members Committee on January 26, 2005, and second vote held on March 17, 2005. In both cases, the proposal failed to gain the necessary (60 percent) support or even a majority. The matter was also considered by the PJM Board at its annual meeting on May 5, 2005.

[99] *PJM Interconnection LLC* in FERC Docket ER05-___-000 and EL05-___-000, August 31, 2005, (RPM Filing).

6. *PJM would mitigate market power through the use of bid mitigation and FERC orders to compel capacity offers.*

7. *PJM would retain the current approach to availability, which measures a unit's "unforced" capacity (UCAP based on average EFORd).*

Forward Auctions and Delivery Years

In a significant departure from the approaches used in New York and New England, the PJM RPM auction approach would use staggered long-term forward auctions to acquire resources up to four (4) years in advance. Each year, a "Base Residual Auction," would acquire capacity resources that would not have to be available until the "Delivery Year," four years hence. With four years to meet the delivery obligation, proposed new resources could presumably participate in the Base Residual Auction against existing resources, providing some protection against the exercise of market power. A four-year lead-time might also allow some "merchant transmission proposals" and demand-side proposals to participate in the auction and compete directly with generation capacity proposals. [100]

Between the year of the Base Residual Auction and the Delivery Year, PJM would also hold three "incremental auctions." Two of these "incremental auctions," would be held 23 months and four months prior to the Delivery Year. These auctions would allow parties to substitute resources for resources that had been committed in the Base Residual Auction but whose delivery had become doubtful for any reasons, such as cancellations, delay, derating or other changes in UCAP ratings, or a decrease in the planned size of a new resource. The costs of any replacement resources committed in these two supplemental auctions would be assigned to the parties making the changes.[101]

A separate "incremental auction" would be held 13 months before the Delivery Year. Its sole purpose would be to allow additional resources to be committed, but only if the ISO determined that unexpected demand growth (100 MW or more, based on revised PJM forecasts 15 months prior to the Delivery Year) or other factors increased the need for capacity resources over the levels committed in the Base Residual Auction. The costs of any resources committed in this supplemental auction would be allocated to all loads.[102]

The sequence and timing of the Base Residual and three incremental auctions is shown in Figure 11.[103]

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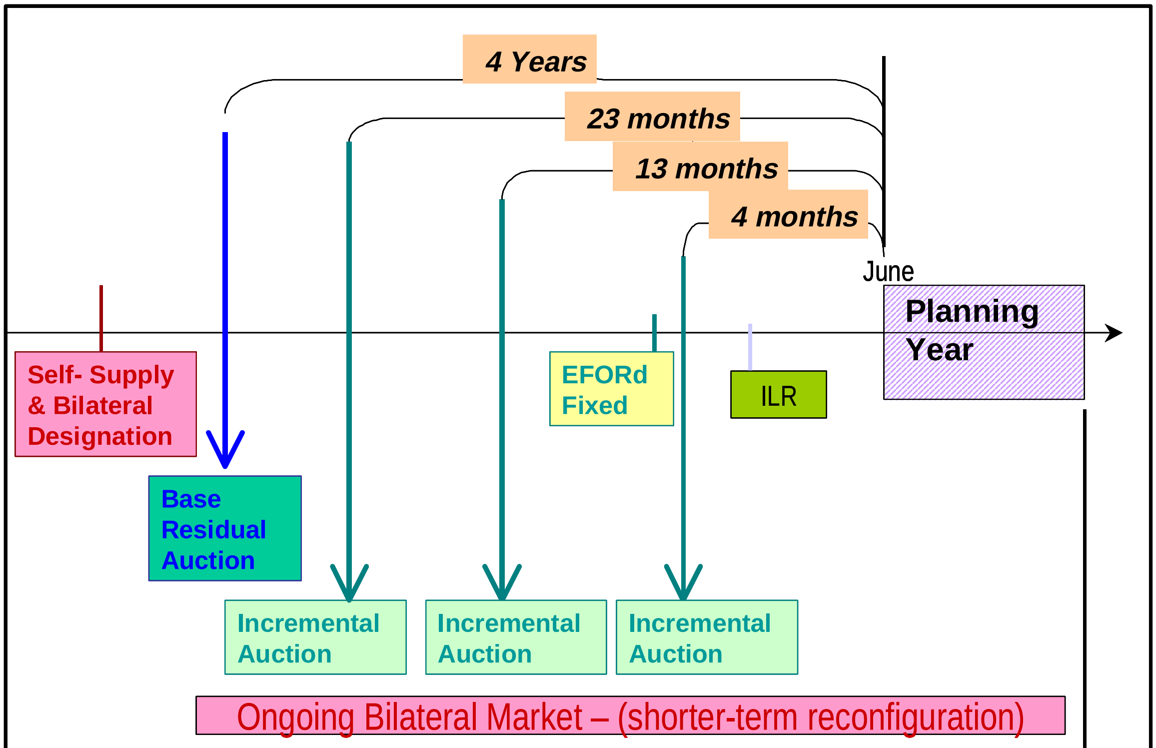
[100] PJM Filing at 52-53.

[101] PJM Filing at 54. All parties with replacements would pay the auction clearing price for replacements, rather than the costs of their specific replacement. Replacement costs for resources needed to relieve a locational constraint would be paid by the buyer whose resource was replaced. PJM Filing, Tab E, Affidavit of Andy Ott (Ott Affidavit) at 8, fn.7.

[102] PJM Filing at 54.

[103] PJM Filing at 52. Once RPM was initiated, there would be transitional measures to acquire resources if needed in years before the first Delivery Year.

Figure 11
Proposed Timing of RPM Auctions



Source: PJM

The PJM proposal also provides an additional opportunity for demand-side resources to enter the market and receive capacity payments. In Figure 11, this is shown as "ILR" which stands for "Interruptible Load for Reliability." ILR providers could offer their resources as late as three months before the Delivery Year and still receive the same capacity prices paid to resources that participated in the Base Residual Auction.[104] The RPM filing notes that PJM will convert load response resources into a comparable measure of capacity so that they can be compared in the same auction as generation; however, the rules for making this conversion are not provided; they are to be developed in the future.

There is a similar requirement for comparing different types of generation on a comparable basis. According to Schedule 9 of the RPM Filing, "The rules and procedures shall recognize the difference in types of generating units and the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include, but are

[104] PJM Filing at 55. PJM would include a forecast of expected ILR resources in defining the remaining requirements for the Base Auctions.

not limited to, fuel availability, stream flow of hydro units, reservoir storage for hydro and pumped storage units, mechanical limitations, and system operating policies." However, these rules are not specified.

In addition to the Base Residual and incremental auctions, PJM proposes a "reliability backstop auction," in the event that the Base and incremental auctions are unable to procure adequate resources. The trigger for this backstop would be four consecutive years in which the Base auction failed to commit the desired level of resources. In that event, it appears PJM could, at any time, hold a backstop auction to acquire whatever resources it deemed necessary to meet reliability requirements; there would be long-run contracts between PJM and the resources.[105]

Settlements for capacity bought and sold in the auctions would not occur until the Delivery Year. That is, while loads would be obligated to pay for their respective shares of the resources acquired in the forward auctions up to four years in advance, their exact obligations would not be determined until the Delivery Year, and payments would not be due until the resources were actually delivered in the Delivery Year. Similarly, resources that cleared the forward auctions would not be paid until the Delivery Year. The structure thus depends on the regulatory certainty that payment obligations incurred in the auction years would be fully honored in each subsequent Delivery Year, for years in the future.

Promotion of Specific Generator Features

In its discussion of the problems it is experiencing with its current ICAP mechanism, PJM notes that between the announced retirements of capacity in Eastern PJM and the few recent capacity additions in its region, there has been a significant decline in generation with specific features that PJM requires to ensure reliable operations. In particular, PJM points out that many of the units planned for retirement were load-following units and/or units capable of starting quickly – that is, within 30 minutes -- and thus able to provide 30-minute operating reserves.[106] To address the decline in these flexible operating features, PJM proposes to identify these two operating capabilities as specific features that would be entitled to additional compensation in the Base Residual and incremental auctions.[107]

PJM proposes to identify, for each LDA/zone, a minimum level of each generation feature needed to reliably operate the system in that zone. The minimum level would then function as a constraint in the solution algorithm for each auction, so that if the constraint were binding, units that offered each of these features could submit higher offers to cover the costs of providing that feature and receive higher clearing prices for providing those features. If either constraint binds in the auction, the price for any resource with the relevant feature would clear at a higher level than necessary to allow the auction to commit the minimum amount of resources

[105] PJM Filing at 55; Ott Affidavit at 32.

[106] Ott Affidavit at 30.

[107] PJM Filing at 53.

with that feature needed for the region. Capacity resources that did not provide these features would receive lower clearing prices.[108]

The PJM RPM Structure Would Be Locational.

PJM proposes initially to create separate LICAP zones for two subregions of PJM. Each zone is called a "Local Deliverability Area," or LDA. One LDA would cover the pre-expansion MAAC area (sometimes called PJM Classic) plus the Allegheny system; the second LDA would cover the expanded areas of PJM (Commonwealth Edison, AEP, Dayton, Virginia/Dominion, and Duquesne systems). These two LDAs/zones would apply for the first year of RPM, proposed as June 1, 2006 through May 31, 2007. These areas are shown in Figure 12, at the end of this section.[109]

Additional LICAP LDA zones would be created in subsequent years, as shown in Figures 13 and 14. For example, by the second year, there would be two additional LDA zones for (1) the Eastern MAAC region of PJM, including the New Jersey, Eastern Pennsylvania and Delmarva peninsula regions, and (2) the Southwestern portion of MAAC, including Baltimore/Washington D.C. More LDA/zones could be created in later years, depending on the findings regarding transmission limits on deliverability, as determined in PJM's annual Regional Transmission Expansion Planning Process (RTEP). The last figure shows the various utility transmission systems that are now part of PJM and used to assess capacity deliverability in the current RTEP process. However, the number of LDAs would not be limited by the number of utility-owned systems but rather by the findings in PJM's RTEP process. In theory, any region or sub region within PJM could eventually become a separate Local Deliverability Area subject to different locational requirements and prices.[110]

PJM would retain its existing deliverability requirements and use the deliverability analysis in the RTEP to identify the need for and boundaries of new LDAs. Thus, each time the RTEP identified an a region of PJM with an existing or approaching deliverability constraint, the ensuing auction process would begin to acquire resources to meet the LDA reliability requirements through capacity additions and/or transmission upgrades to relieve the constraint.[111] It is worth noting that while the RPM structure would use forward auctions to procure resources four years in advance, the risks of long-run contracts would be affected by the fact that the number and boundaries of LDAs could change from year to year, and these could change dramatically during the first few years of RPM implementation, leaving parties exposed to risks of possible locational price differences but no clear way to hedge these risks.

[108] PJM Filing at 58-59; Ott Affidavit at 31.

[109] All figures showing the possible LDA zones are taken from the PJM RMP Filing, Affidavit of Steve Herling (Herling Affidavit), Attachment 3.

[110] PJM Filing at 57-58; Herling Affidavit at 10-11.

[111] PJM Filing at 60; Herling Affidavit at 11.

PJM's deliverability analyses compare each region's Capacity Emergency Transfer Objective (CETO), which is "the amount of capacity that must be imported into an area during an emergency to ensure that the area can satisfy a transmission related loss of load expectation of only one day in 25 years," and the area's Capacity Emergency Transfer Limit (CETL) which is "the capability of the transmission system to transfer capacity into that area under those emergency conditions."[112] If this comparison shows that the CETO for an area exceeds the CETL for that area, the RTEP would specify transmission upgrades ("base upgrades") needed to increase the existing CETL up to the CETO (the area's import objective). This is the current process. What is new under RPM is that such a finding would also trigger the creation of an LDA, a zone for which capacity requirements and prices could differ in the next RPM auctions.[113] Note that the criteria for signaling the need for an upgrade and for triggering an LDA is a one-day in 25-years LOLE, which is significantly more stringent than the 1-day in 10-year LOLE criterion used to define PJM's UCAP reserve objective.

Each auction would take into account the resource offers in each LDA and the constraints (Transfer Limits) in delivering energy into each LDA, along with resource offers external to each LDA. When transmission constraints were binding in the forward auctions, such that less expensive resources could not be imported into an LDA, prices would differ between the LDAs. Generators with eligible capacity that cleared the market in the periodic auctions would receive the Final Capacity Prices in those auctions for their respective LDA. Each LSE would pay the Final Capacity Prices for its respective LDA times the its Daily Unforced Capacity Obligation. The amount paid by load is called the "Locational Reliability Charge."[114]

Because Capacity prices could vary between LDAs, parties that owned or contracted with capacity might face locational differences in the clearing price in the generator's LDA and the load's LDA. The difference between the generator's LDA price and the load LDA's price is called a "Locational Price Adder." Thus, a load that relied on generation located outside its own LDA would pay its own LDA prices plus the Locational Price Adder for the right to rely on that external resource to meet its share of the adequacy requirement. At the same time, loads would be allocated "Capacity Transfer Rights" (CTRs), which is somewhat analogous to the Financial Transmission Rights in the LMP-based energy markets. CTRs would entitle the loads to receive the Locational Price Adder for the amount of capacity resources equal to their allocated CTRs.[115]

Capacity Transfer Rights would be allocated pro rata to loads in each LDA. The CTR allocation to each Load Serving Entity would correspond to each LSE's pro rata share (given its capacity obligation, which is determined daily) of the capacity imported into its LDA. However, the total allocated in this manner would first be reduced by any specific allocations to entities that had paid for upgrades to increase the import capability into that LDA. These might include generators that had paid for upgrades as part of their interconnection agreements to ensure

[112] Herling Affidavit at 5, 11.

[113] Id.

[114] PJM Filing at 53, 56, 59.

[115] PJM Filing at 59.

deliverability of their capacity. This implies that entities that built or paid for new upgrades in the future would also receive a corresponding allocation of CTRs to reflect the incremental expansion in the CETL into a given LDA.[116]

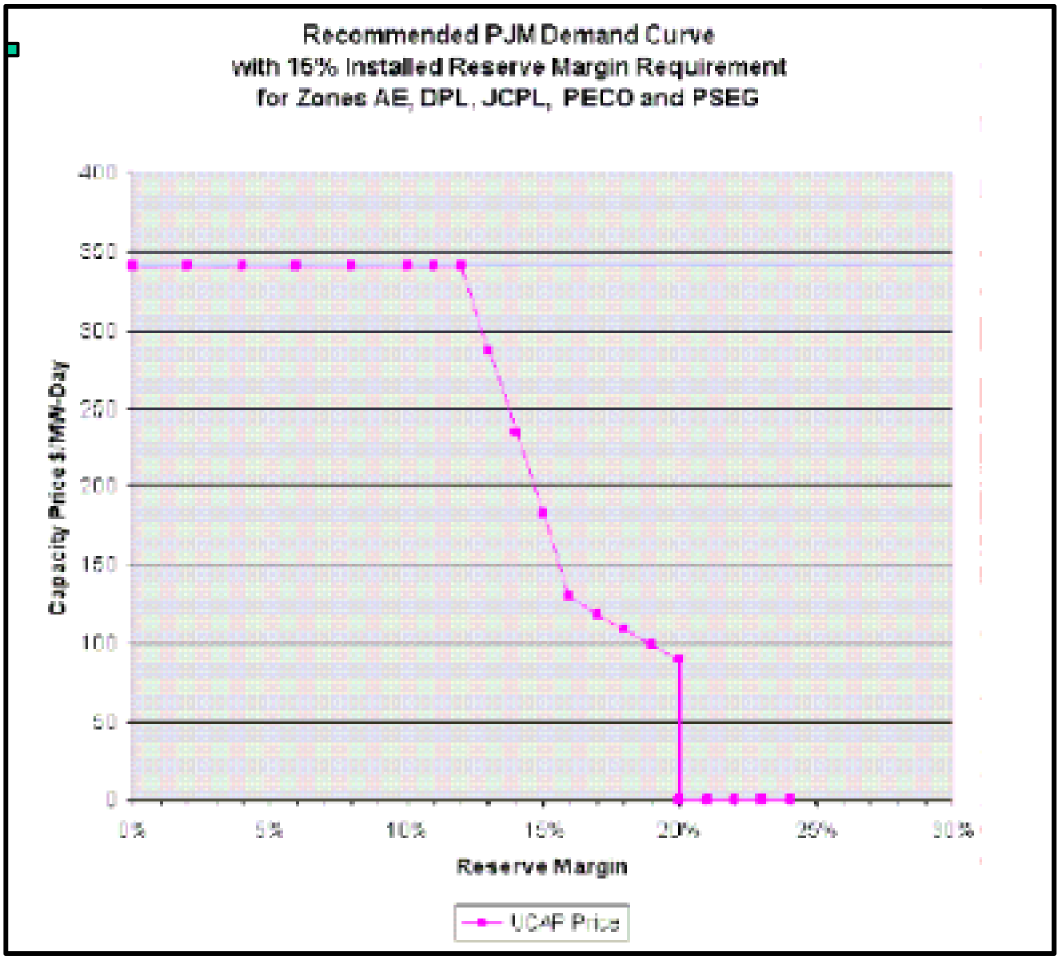
It is unclear from the RPM filing how the possibility of multiple LDAs beyond the initial two would affect how locational requirements in each LDA were set, how the CTRs would be defined and how they might function. The basic approach can be understood if applied to a relatively simple radial configuration with no network effects. However, it is not clear how the system could work in a more complex network in which simultaneous transfer limits would vary depending on the transfers from one LDA versus a second LDA into a third LDA, or where one LDA might be nested inside another LDA. The initial filing does not fully address this potential complexity, and this is a topic for further inquiry. However, this concern would likely not arise in the initial year or two of the PJM mechanism, because of the limited number of zones involved and their apparent radial connection.

PJM's RPM Uses a Downward Sloping Variable Resource Requirement Curve.

PJM describes its "demand" curve as a "variable resource requirement" (VRR) curve. These terms appear to acknowledge that this is not technically a "demand curve" in the classic economic sense. Instead, it is a curve designed to meet a reliability standard – a reserve margin consistent with the 1-day in 10-year LOLE criterion set by NERC (North American Electric Reliability Council) – while allowing the auction price of resources to vary with the level of resources offered relative to that standard. The design of the PJM VRR curve reflects the investment requirements of capacity resources at the target level of reserves. This is essentially what the New York and ISO-NE "demand" curves are trying to do. A generic version of the PJM proposed VRR curve for one region is shown in Figure 15.

[116] Herling Affidavit at 13.

Figure 15
Proposed PJM Demand Curve



PJM's propose VRR curve reflects the same basic concepts used to design the downward sloping curves in New York and New England.

1. The PJM curve centers on the conjunction of the breakeven point for recovering fixed costs for the benchmark unit at the target level of reserves *plus one percent*. The target level is set at 15 percent reserves above the expected peak demand, reflecting (approximately) a 1-day in 10-year LOLE for the PJM region as a whole.[117] The breakeven point is at the cost of new entry (called "CONE" in PJM) for the benchmark unit (PJM calls this the "Reference" plant) *net* of any contribution to fixed cost earned by the Reference unit from PJM energy markets and ancillary service payments.[118] (This is

[117] It appears that PJM would not calculate a separate reserve margin corresponding to 1-day-in 10-year LOLE for each LDA. The same 15 percent margin would be used for all areas.

[118] PJM has markets for regulation but not other operating reserves. However, generators are paid "make whole payments" for net costs of commitment or providing reserves, such as start-up and minimum generation costs, that are not recovered through the energy markets when the units are dispatched. In the calculation of net CONE, PJM

similar to the approach used in New York, but not in ISO-NE, where net revenues from the energy markets are not netted from the cost of energy or used to design the curve but are instead subtracted later, from the LICAP payments.) As in the NY and ISO-NE approaches, the benchmark/Reference unit is a frame combustion turbine (CT).

2. The curve has a zero crossing point, at 20 percent reserves, which is five percent higher reserves than the target level. Note, however, that the curve is truncated on the right side to force a zero crossing point at 20 percent reserves, rather than extending the curve out to the left (e.g., to 25 percent reserves or more, as originally proposed in the November 2004 *White Paper*). PJM made this change in response to comments from state regulators, who argued against making capacity payments when capacity levels went significantly beyond the target.[119]

3. There is a capacity price cap, set at two times the net cost of new entry for the Reference unit.

4. As in New England, the PJM curve also has a "kink," which allows a steeper slope for the left side of the curve (when reserves fall below the target) and a shallower slope for the right side of the curve (when reserves exceed the target level, until the curve meets the capacity level for zero price. In the PJM VRR curve, the kink occurs at the point corresponding to one percent above the 15 percent reserve target (i.e. at 16 percent reserves) and the net CONE. The choice of this parameter is discussed further below.

5. In the PJM approach, there is no attempt to determine or replicate historic capacity/reserve levels. Recall that in the ISO-NE proposed curve, the designer's intent is to encourage a level of capacity that does not fall below the reliability criterion of 1-day in 10-years LOLE more than 17 percent of the time, to reflect the ISO's view of historic practice in New England.

6. As in New York and New England, each LDA in PJM would have a slightly different demand curve, reflecting the different net cost of new entry for the benchmark/Reference unit in each zone. PJM proposes to reexamine the parameters of its proposed curve(s) "at least every three years."[120]

In selecting the parameters of its proposed curve, PJM undertook economic analyses of the likely investment responses to five alternative VRR curves using different parameters. One alternative VRR curve attempted to define the curve based on an assumed value of lost load (VOLL-Based Curve). A second alternative was the original curve proposed in the November

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includes a fixed contribution for ancillary services, set at $2,254 per MW-year, while noting that the Reference unit, a CT, is not likely to be providing most types of ancillary services. PJM Filing, Affidavit of Joe Bowring (Bowring Affidavit) at 6.

[119] PJM Filing at 53.

[120] Ott Affidavit at 23.

2004 White Paper. The third, or base curve plus two additional curves shifted 1 percent and 5 percent, respectively, to the right of the base curve were also considered. [121]

PJM describes the base curve (curve #3) as follows:

> "A downward sloping demand curve with four segments: (a) a horizontal segment with an ICAP price equal to two times the fixed costs of a turbine if the reserves are less than 96% of the target reserves, minus the average [energy and ancillary services] gross margin, divided by one minus the forced outage rate: (b) another horizontal segment with a zero price if the installed capacity exceeds the target installed reserve margin of 15% by 5% or more; and (c) two linear downward sloping segments located between the other two, with the right-hand one having a shallower slope. The slope of these two lines changes at a point where capacity equals the IRM, and price equals CONE minus [sic] the average E/AS gross margin, divided by one minus the forced outage rate [for the Reference unit]."[122]

The final proposed curve appears to be Alternative 4, in which the base curve has been shifted "1 percent to the right." This appears to mean that the "kink" in the curve is moved right so that it is one percent higher than the 15 percent reserve target (i.e., 16 percent), but the zero crossing point is *not* moved to the right (it is still at 20 percent reserves). The effect of shifting the kink, and only the kink, one percent to the right is to make the slope of the left side of the curve slightly flatter but also to extend that part of the curve further to the right, increasing total capacity payments during periods when reserves are below the target level.

According to PJM, its economic analyses show that among the alternatives considered, alternative curve 4 would achieve the highest degree of compliance with the Installed Reserve Margin (IRM) requirement. PJM claims this curve would induce investments such that the region would achieve reserve levels equal to or greater than the IRM 98 percent of the years, with average reserves expected to be only 1.79 percent above the 15 percent IRM target.[123]

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[121] PJM Filing at 62-66. The economic analyses comparing the expected investment costs and performance under each alternative curve was performed by Professor Benjamin Hobbs with evaluation from Andy Ott. See, PJM RPM Filing, Tab E, Affidavit of Andrew L. Ott (Ott Affidavit) at 17 and Tab H, Affidavit of Professor Benjamin F. Hobbs, (Hobbs Affidavit). To perform his analyses, Professor Hobbs developed "a dynamic model that simulates generation investment over time in response to incentives in the energy, ancillary services and capacity markets." Hobbs Affidavit at 6.

[122] PJM Filing, at 62.

[123] The ISO-NE claims for its proposed demand curve are more modest. While noting that the ISO-NE curve might work better than the ISO assumed, the ISO claimed only that its curve would not fall below the reliability criterion more than 17 percent of the years, and thus be at or above that criterion 83 percent of the years, compared to the PJM claim for its curve of 98 percent at or above the criterion. At C_{target}, the average reserve claimed by ISO-NE would be about 5 percent above the criterion, compared to the 1.79 percent claimed by PJM, suggesting much lower variability relative to the target for the PJM curve. Note, however, these are only the claimed results; there has been no attempt to systematically compare the different analyses performed by the two ISOs. Recall that ISO-NE *assumed* the variability resulting from its curve would be the same as experienced historically, but ISO-NE did not explicitly predict how its curve would perform, whereas PJM is attempting to predict the variability its curve will experience. Another part of this difference may be driven by the difference between ISO-NE's monthly auctions and PJM's four-year forward auctions.

Alternative curve 4 also has the lowest total consumer payments, though only slightly different from Alternatives 3 and 5.[124]

According to the analysis performed by Professor Hobbs, the principal effect of the "1 percent shift to the right" relative to the base curve is to increase the percentage of years in which the amount of capacity would meet or exceed the 15 percent reserve target (from 92 percent to 98 percent), while slightly decreasing the total costs to consumers. Although this shift slightly increases the amount of capacity, the increased capital cost is more than offset by the decrease in scarcity payments for energy.[125]

Determination of Auction Prices Under RPM

Unlike ISO-NE's proposal, PJM would define auction market clearing prices based on the intersection of the administratively defined demand curve and a supply curve composed of the capacity price offers of eligible capacity providers, as well as equivalent offers derived from offers by merchant transmission providers to expand the transfer capability between a generation LDA and load LDA. Demand response proposals meeting resource adequacy criteria would also be allowed to compete. Sellers of capacity resources with offers at or below the clearing price would be committed to meet their respective LDA's capacity requirements in the Delivery Year and would be paid the clearing price in the Delivery Year.[126] The proposal also includes a form of shortage pricing, so that if offered resources are insufficient to meet the VRR (demand) curve, the clearing price would be set by the demand curve.[127]

Using a Variable Resource Requirement curve means that PJM would at times acquire more capacity than required for a fixed resource requirement, such as 15 percent reserves. But the slope of the proposed VRR curve is such that when PJM acquires more than the 15 percent reserve level, the total cost of capacity is less than what PJM would pay if the reserve level could somehow be kept right at 15 percent.[128]

Settlements would be on a net basis for loads that owned generation or had bilateral contracts with generation. Load serving entities with bilateral or owned generation would offer their capacity into the auction at a "price taker" bid. Each LSE would receive or pay the

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[124] A table summarizing the expected performance of the alternative curves analyzed by Professor Hobbs is shown at PJM RPM Filing at 65, Table 3.

[125] PJM RPM Filing at 65; Ott Affidavit at 25.

[126] Ott Affidavit at 8. However, capacity resources with lower offers but with operating constraints might be rejected in favor of capacity resources with slightly higher offers but without such constraints. The auction algorithm would optimize these choices.

[127] Ott Affidavit at 8, and see Figure 5, Ott Affidavit at 10.

[128] This result is illustrated by Figures 5 and 6 in Ott Affidavit at 10.

Capacity Price for their net capacity (UCAP) sales or purchases, relative to their pro rata UCAP requirements.[129]

With respect to demand-side capacity resources, PJM notes that these can receive credit in energy markets but currently there is no way for them to receive credit for capacity. By allowing demand resources (DR) to participate in the RPM auctions, PJM intends to provide a means for DR to recover capital requirements that might not otherwise be recoverable from energy market revenues only. DR that wished to bid into the Base and Supplemental auctions would be called "demand as a resource." DR that did not participate in any auction could still be eligible for capacity payments by offering ILR – interruptible load for reliability – as late as three months prior to the Delivery Year. To be eligible, an ILR must meet the current requirements for PJM's existing "Active Load Management" program. ALM resources may offer up to 10 6-hour interruptions per year when called upon by PJM. An ILR provider would receive a credit against its RPM reliability charge, which will offset both the regional charge and the Locational Price Adder for the provider's LDA.[130]

With respect to transmission resources, an eligible transmission upgrade must (1) increase the CETL into an LDA, (2) demonstrate that it will be in service at the beginning of the Delivery Year, and (3) be funded by the proponent through a specified rate. The planned upgrade must have, at least 45 days prior to the auction, a certificate from PJM indicating its increase in the CETL and a signed Facilities Study Agreement, and be consistent with the most recent RTEP. The transmission alternative's offer price would be expressed in terms of the Locational Price Adder (that is, the amount by which the upgrade increases the Capacity Emergency Transfer Limits (CETL) and creates the ability to capture the difference between the capacity price in the load zone and the capacity price in the generator's zone).[131]

RPM auction prices would vary by season

PJM proposes that RPM auction prices vary by season. To allow this, resources would have the option to vary the price (but not the quantity) of their resource offers by season. PJM would then clear the auctions separately for each season of a Delivery Year. While an offer from a generation resource would be for a fixed quantity for the entire Delivery Year, the resource might not clear the auction in every season of that year; in that event, it would be obligated to provide the capacity only in the seasons in which its capacity cleared the auction. A demand resource (ILR) could submit a bid only for a season, such as summer. If its bid cleared the auction, it would be obligated to provide the ILR resources only during the season for which it

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[129] PJM Filing at 53; Ott Affidavit at 12-13. Ott notes that there may be differences between the clearing prices in the Base Auction and the final net settlements, due to additional capacity purchased in the 2nd supplemental auction, missed estimates of the amount of ILR (interruptible load resources) obtained by the Delivery Year, and different prices for resources that do or do not have the two specified generator characteristics (quick start and load following).

[130] Ott Affidavit at 27. The ILR offset would not offset that extra portion of the reliability charge that pays for the specified generation features of load following and 30-minute start capability.

[131] Herling Affidavit at 15-16.

cleared the auction. Resources that submitted the same price offers for the entire year and cleared the auction (at the average clearing price) would receive a price equal to the average of the four seasonal clearing prices.[132]

Mitigation of Market Power Under RPM

Given an approach that allows resource offers to determine prices, there would be an opportunity to increase auction clearing prices through either physical or economic withholding. The RPM proposal contains mitigation approaches for both physical withholding and economic withholding.

To address physical withholding, the PJM Market Monitor would compare known amounts of capacity owned by various parties with capacity actually offered in the auctions either by the generation owner or by a load with bilateral contracts, along with evidence of capacity that had been delisted for possible export to neighboring markets. Each unit must offer its expected level of unforced capacity (UCAP) into an auction for all four seasons of the Delivery Year to be eligible for payments that year, with the UCAP rating reflecting an EFORd equal to or better than the average of the previous 12 months. The only exceptions to the implied "must offer" obligation would be for units expected to be out for the Delivery Year, capacity contractually committed to sales in another market, or units originally interconnected as energy-only units. Capacity not offered and not excepted would not be allowed to sell capacity in any way during the Delivery Year. Evidence of physical withholding would then be subject to further investigation and possible remedies, including a request for a FERC Order to compel a resource owner to offer its capacity into the auction. An auction could be delayed to allow PJM to pursue this remedy.[133]

To address possible economic withholding, the Market Monitor would first determine whether an LDA was structurally competitive, using three different tests; if an LDA failed these tests, resource offers within that LDA would be subject to potential mitigation prior to the end of each auction. The Market Monitor would compare resource offers for each unit against predetermined estimates of what competitive offers should be. A competitive offer would be assumed to equal the incremental costs for each unit of providing capacity from that unit, which would be based on that unit's total annual avoidable costs less net revenue that unit would receive from other PJM markets.[134] Offers above these estimates would then trigger a screening analysis of the price effects, and if this screen were failed, offers would be mitigated.[135]

Market structure screens would define the need for mitigation

Under RPM, PJM would first determine whether PJM as a whole, or any LPA region, required market power mitigation. PJM would apply a "preliminary screen" to determine whether the

[132] Ott Affidavit at 28-28
[133] Bowring Affidavit at 22.

[134] Bowring Affidavit at 17.

[135] Bowring Affidavit at 23.

conditions in the applicable region would permit the exercise of market power. This screen would consider the unforced capacity available to the region for the delivery year, the demand for capacity in the region for that year, and firm obligations to sell unforced capacity from resources in the region. After accounting for any transmission limits into the region, PJM would compile a potential supply curve for meeting the remaining demand for capacity. This curve would be evaluated for the potential to exercise market power.[136]

The preliminary screen would consider three tests: (1) the market shares of individual sellers, with "failure" occurring for any seller with a share in excess of 20 percent; (2) market concentration, with failure defined as an HHI greater than 1800; and (3) a pivotal suppliers test, with failure occurring if there were three or fewer pivotal suppliers – that is, the market could not clear without the supply from these three or fewer suppliers. Failing any one of the three tests would trigger data requirements from sellers and further examination of the need for possible mitigation, but the third screen ("no three pivotal suppliers") is critical. According to PJM, failing the first two screens triggers a demand for more data, but failing the third screen would trigger offer caps:

> "Only the [three pivotal supplier test] is needed because, if it is passed, no mitigation is needed regardless of the outcome of market share and HHI tests, whereas, if it is failed, mitigation is needed regardless of the outcome of the other tests."[137]

In other words, if there are four or more pivotal suppliers, the market is deemed competitive enough not to require mitigation, but if there are three or fewer pivotal suppliers, offer cap mitigation is assumed to be needed when transmission is binding.

PJM would thus apply this structural test in each auction. If a transmission constraint into an LDA became binding in solving the auction, the market structure test would be applied. If it failed, offers into the LDA experiencing the constraint would be subject to unit specific market seller offer caps. These offer caps would thus be applied in the auctions, but only if the constraints into an LDA (or PJM as a region) were binding so as to create different prices (a positive locational price adder), *and* "if the sell offers that are available to the PJM auction clearing algorithm to resolve the local constraints fail the market structure test."[138]

However, sell offers from new entrants would not be subject to offer caps, because "new entry is assumed to be competitive." An offer based on "new entry" would require an executed facilities study agreement or an interconnection service agreement prior to the auction.[139]

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[136] Bowring Affidavit at 18.

[137] Bowring Affidavit at 19.

[138] Bowring Aff. at 21.

[139] Bowring Aff. at 22.

Design of market seller offer caps

PJM would develop offer caps on a unit specific basis, in an effort to emulate "competitive" offers. PJM defines a competitive offer as:

> " . . .the annual avoidable cost of the unit, less net revenues from other PJM markets, including the bilateral sale of any product from the unit. This is a competitive offer because it reflects the incremental cost of capacity for a year. If a unit has avoidable costs of $100 per MW-day and net revenues from other PJM markets of $30 per MW-day, the increment cost of maintaining the unit for a year in order to sell capacity is the difference, $70 per MW-day."[140]

Avoidable costs would be costs that the seller would avoid if the unit shut down. This might include capital investment costs that the owner might need to incur to keep a unit operable during the Delivery Year. Compared to previously approved avoidable costs to defer a retirement, PJM would include a 10 percent adder to reflect uncertainty associated with avoidable costs four years out. The net revenues from other PJM markets would be determined on a unit specific basis.[141]

The design of seller offer caps would also take into account three factors: (1) the risks that a unit's EFORd might change in the period between the auction and the Delivery Year; (2) opportunity costs faced by a unit; and (3) firm obligations to sell. With respect to opportunity cost, PJM would recognize the ability of a unit to sell its capacity into a neighboring market outside PJM. If a unit could document this opportunity, an offer into the PJM market at this opportunity cost would not be mitigated. Similarly, PJM would recognize a unit that had a firm obligation to sell, such as through a bilateral contract, an obligation to serve own loads or to serve default supply obligations. These sellers would be required to offer their capacity into the PJM RPM auctions as price takers.[142]

PJM would specifically design the offer caps to account for EFORd risks, recognizing that EFORd is an "historical measure" that may not reflect the amount of UCAP a unit might have available during a Delivery Year.

> "[EFORd] is a relatively week incentive for capacity resources to perform in the delivery year. EFORd risk in the RPM derives from the fact that an EFORd rate must be specified at the time an existing unit is offered into the RPM auction while the amount of unforced capacity actually sold [provided] in the delivery year depends on the 12 month EFORd for a period ending three months prior to the delivery year."[143]

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[140] Bowring Aff. at 19.

[141] Bowring Aff. at 19, 23.

[142] Id. at 21.

[143] Id, at 20.

To allow capacity sellers to address this risk when fashioning a "competitive offer" for an offer cap, PJM proposes to allow a part of each unit's capacity to be offered at the net cost of new entry. Each unit subject to offer mitigation would thus be allowed a base offer defined by the avoidable costs net of market revenues for most of its capacity and an "EFORd offer segment" defined by the net CONE. The idea is that the net CONE is what a seller would have to pay in the auction for any UCAP not supplied by its unit as a result of a worsening of its EFORd rate. To reflect expected variations in EFORd, the amount of capacity subject to the EFORd offer segment would be the difference between a unit's five year average and 12 month average EFORd ratings, or some other expected difference anticipated for each unit if that could be documented.[144]

Continued Use of UCAP as the Availability Metric

There do not appear to be any changes from the current availability metric. Further, PJM would continue to rely on the current system of "deficiency charges" to penalize resource providers for any failure to perform in making their resource available during the Delivery Year. There would be additional rules applicable to new transmission and demand-side response providers.[145]

[144] Id. at 20-21.

[145] PJM Filing at 55.

Figure 12
Locational Deliverability Areas, 2006/2007

Attachment 3: Locational Deliverability Areas – 2006/2007

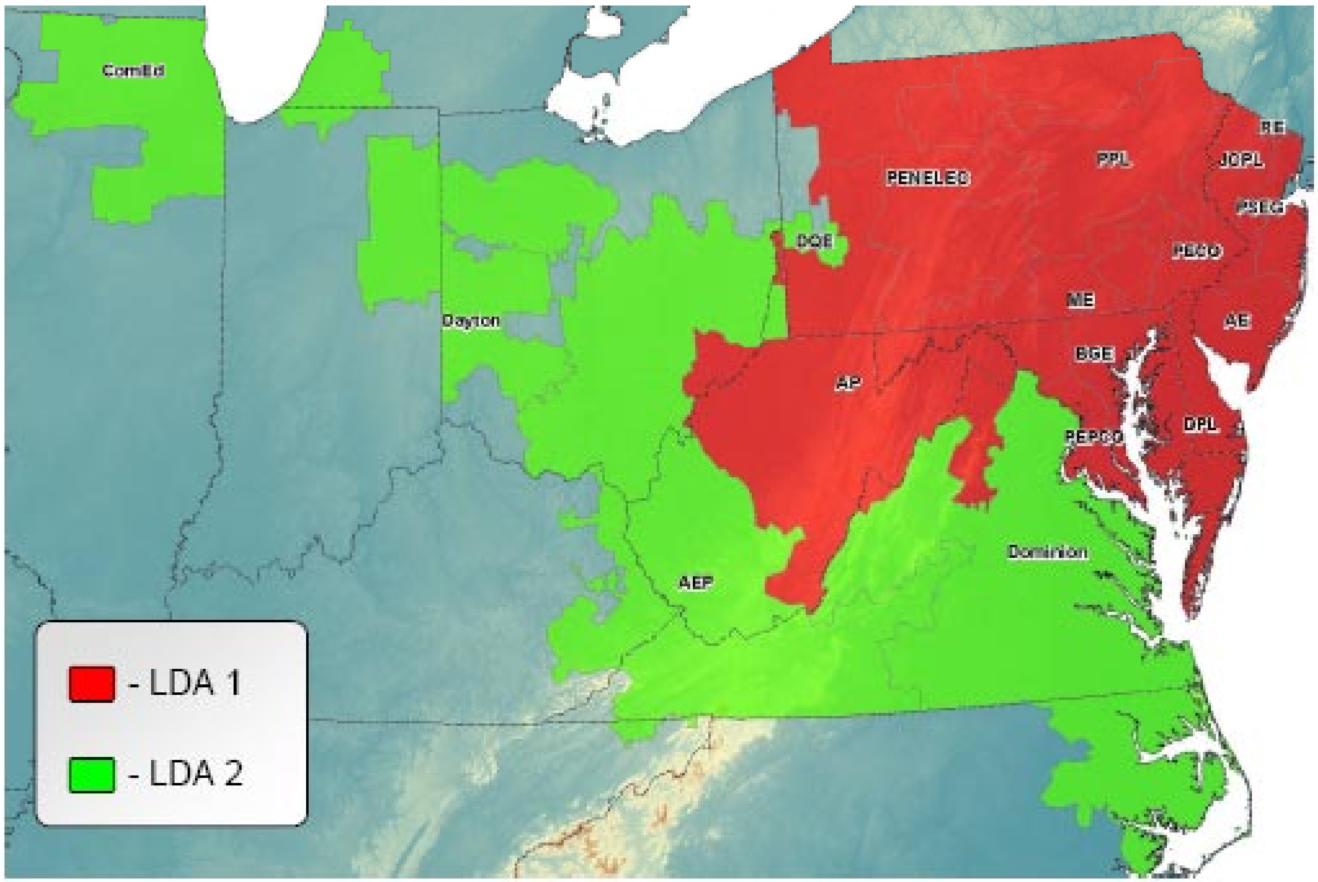


Figure 13
Locational Deliverability Areas, 2006/2007

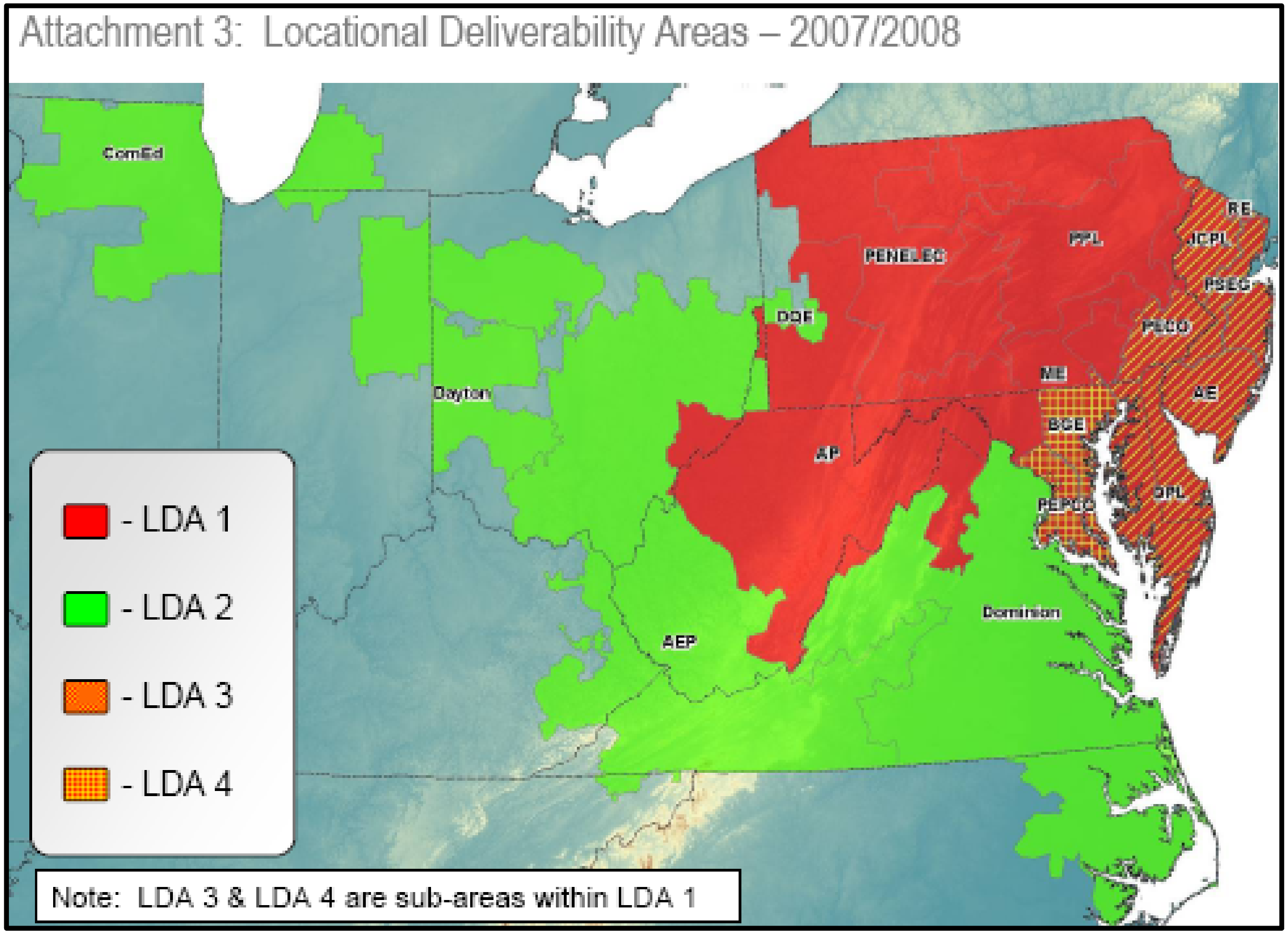
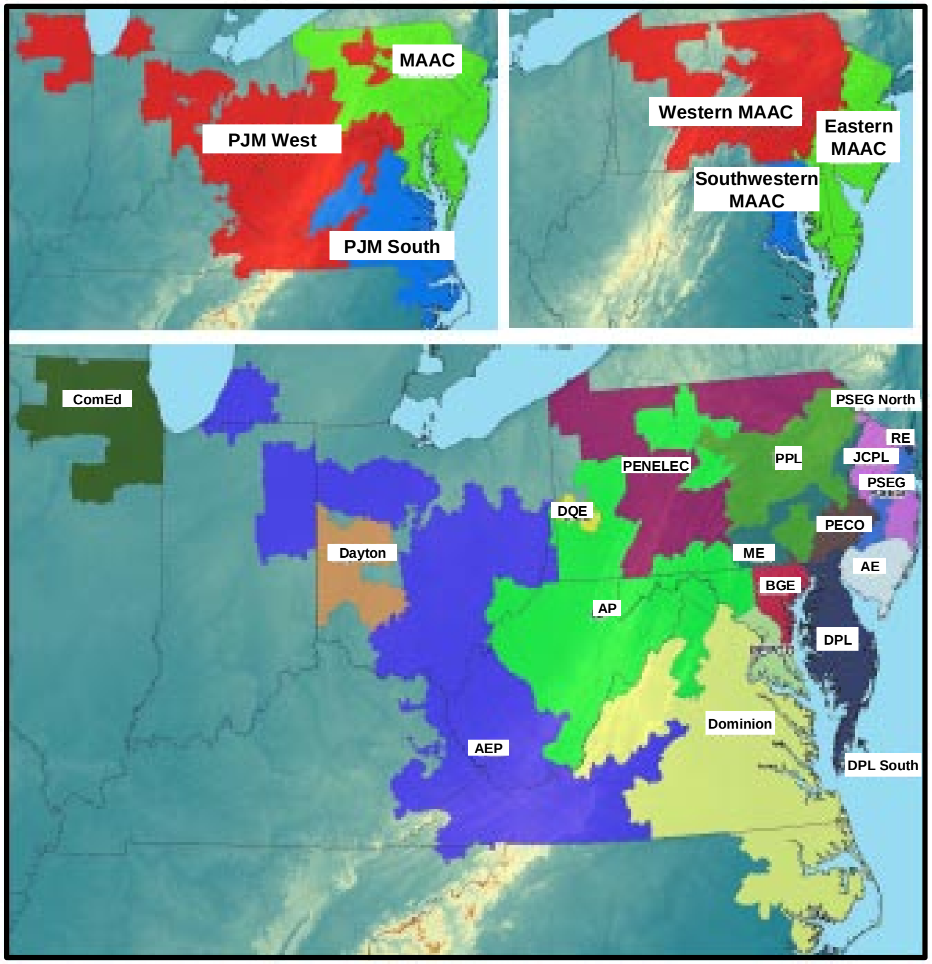


Figure 14
Locational Deliverability Areas – 2008/2009 and 2009/2010



Tables 2 and 3: Comparison of ISO Locational Features

Internal Capacity Transfer Limits

	Explicit	Model exports from LICAP regions	Model multiple nested LICAP regions
NYISO	No	No	No
ISO-NE	Yes	Yes	Yes
PJM RPM	Yes	No	No

Internal Capacity Transfer Rights

	Explicit	Financial	What determines quantity	Allows preferential allocation	Who gets the rights?	What rights do import constrained LSEs get?	Follow the load
NYISO	No	No	Difference between NYCA and Locational capacity requirement	No	LSEs in the import constrained areas	On their immediate import constraint	Yes
ISO-NE	Yes	Yes	LICAP Region import constraint	Yes	LSEs in the import constrained areas (and resources in export constrained areas as in March 1 filing)	On all import constraints into their LICAP region	Yes
PJM RPM	Yes	Yes	LDA import constraint	Yes	LSEs in the import constrained areas and MPs that bear the cost of incremental capacity	To deliver capacity from the rest of PJM	Yes

APPENDIX A: FERC ORDERS AND FILINGS RELATING TO THE PJM RPM PROPOSAL

April 2, 2003

- Reliant Energy Mid-Atlantic Power Holdings, LLC ("Reliant") submits a complaint against PJM Interconnection LLC (PJM) alleging a significant design flaw in PJM's market design such that it fails to appropriately reflect and compensate Reliant generators that provide reliability services. Reliant proposes an interim tariff design to remedy the shortcomings of the PJM market until an alternative plan can be instituted. Reliant then proposes an alternative market design including three main components: (1) identification of Reliant generators subject to the proposal, (2) new provisions for mitigation of these facilities, and (3) a CT Proxy design similar to the one created by the New England ISO. The CT Proxy system would allow generators to bid up to a "safe harbor" threshold without mitigation in order to recover high costs necessary for providing reliability.
- – *Request for Approval of a Formula Proxy CT Methodology for Certain Reliant Energy Mid-Atlantic Power Holdings, LLC Generating Facilities in PJM Interconnect* in FERC Docket EL03-116-000 (April 2, 2003 Filing)

July 9, 2003

- FERC denies Reliant's April 2, 2003 complaint, explaining the Reliant has not provided significant data showing that its units in PJM could not recover fixed and variable costs. The Commission also states that Reliant also did not show that the mechanism designed by PJM does not provide units with a reasonable opportunity to recover their costs, nor did it show that the offer caps set by PJM provide insufficient revenues to create incentive for new entry. While it rejects Reliant's complaint, the Commission also notes that the current provisions in the PJM region may not be the most appropriate for providing cost recovery to reliability must run (RMR) units, and directs PJM to file a revised Tariff or justification for its existing Tariff by September 30, 2003.
- – *Order Denying Complaint* 104 FERC ¶ 61,040 (July 9, 2003 Order)

September 30, 2003

- PJM submits a filing in compliance with FERC's July 9th order amending its Open Access Transmission Tariff. PJM proposes revising the price cap rules for RMR generators, but says that it will continue to cap prices on units dispatched out of economic merit for reliability purposes. PJM also acknowledges the need to modify its local market rules to effectively address long-term scarcity should such a condition arise. They propose a competitive auction to be triggered when long-term scarcity is identified in a load pocket. The filing also includes proposes eliminating price capping in load pockets deemed competitive by PJM, as well as eliminating the existing exemption of post-1996 generating units from capping provisions.
- – *PJM Interconnection LLC* in FERC Docket EL03-236-000 (September 30, 2003 Filing)

December 19, 2003

- FERC issues an order recognizing that the issue of how to price RMR generators has arisen in other regions that PJM, and that it has important implications for generation infrastructure and the operation of an efficient wholesale marketplace. Therefore, the Commission orders the establishment of a two part technical conference on February 4th and 5th, 2005. The first part of the conference is to focus on the broad issue of pricing RMR units, and the second on PJM's specific proposal filed on September 30th.
- – *Order Establishing Staff Technical Conference* 105 FERC ¶ 61,312 (December 19, 2003 Order)

May 6, 2004

- FERC order announcing the establishment of a general Reliability Compensation Policy. In this order, the Commission states while there may not be one uniform solution to Reliability Compensation Issues in every region, the approach to resolving these issues should be uniform and transparent. The Commission then provides step-by-step guidance for developing the most effective solutions possible. The Commission also rules on PJM's September 30, 2003 filing in this order. They find that PJM's current methodology for price capping works effectively to mitigate market power in a manner that is fair to most generating units. They propose two changes to the Tariff to provide clear rules for PJM and its generators. The first is that PJM must provide units that are frequently mitigated the right to receive higher price caps or alternative compensation, where frequently mitigated units are those that are mitigated for 80% or more of their run hours, are needed for reliability, and are not recovering sufficient revenues to cover their costs. The second FERC directive is that PJM must provide a process for procedure if bilateral negotiations between PJM and RMR units fail. The Commission also orders PJM to investigate the use of alternative pricing that recognizes operating reserve deficiencies in the market design.
- – *Order on Tariff Filing* 107 FERC ¶ 61,112 (May 6, 2004 Order)

July 16, 2004

- PJM submits a compliance filing in response to the Commission's order on May 6, 2004. PJM alters the rule that suspends price capping in any hour in which there are not three or fewer generation suppliers available for dispatch, or the "no three" rule, establishing it as a clearly stated trigger for the suspension of offer caps.
- – *PJM Interconnection LLC (Compliance Filing)* in FERC Docket EL03-236-002 (July 16, 2004 Filing)

November 2, 2004

- PJM submits a second filing in compliance with FERC's May 6, 2004 order, which directs PJM to address compensation for frequently mitigated units as well as to investigate the expected impacts of adopting a pricing system that recognizes operating reserves shortages. PJM revises the Tariff to say that a frequently mitigated unit shall now have an offer cap of its incremental operating costs plus $40 per megawatt hour, or that an alternative cap may be specified in unit specific agreements between PJM and the generator owner. The new Tariff also dictates that agreements between PJM and generator owners will are not effective until they are accepted by the Commission. Addressing the issue of the effect of a pricing system that recognized operating reserve shortages on its current market design, PJM states that its current market design already ensures sufficient operating reserves and therefore does not need to consider alternative pricing to address scarcity conditions.

– *PJM Interconnection LLC (Compliance Filing)* in FERC Docket EL03-236-003 (November 2, 2004 Filing)

January 25, 2005

- FERC denies in part and grants in part requests for rehearing of the compliance filings submitted by PJM on July 16, 2004 and November 2, 2004. It accepts PJM's report that it does not need to consider alternative pricing to address scarcity conditions. The Commission directs PJM to implement the revised "no three" rule that PJM proposed in the July 16th order. The order also requires PJM to file another clarification and revised Tariff sheet within 30 days of the issuance of the order.

– *Order on Rehearing and Compliance Filings and Terminating Proceedings* 110 FERC ¶ 61,053 (January 25, 2005 Order)

February 24, 2005

- Reliant submits a request for the rehearing of FERC's January 25, 2005 order based on two main specified errors: (1) the "no three" rule proposed by PJM is not just and is unreasonable and (2) the Commission made an error in applying the grandfather provisions related to post 1996 units based upon the date which the unit's zone was approved for integration into PJM. Reliant says that the Commission's approval of the flawed "no three" test, even in the interim until a more appropriate test can be implemented, serves only to hinder competition in the electricity market in the future, and offers several alternatives tests. Reliant goes on to suggest that rather than applying to grandfather provisions based upon the date of generator's integration into PJM, the Commission should adopt a rebuttable presumption that generators constructed between April 1, 1999 and September 30, 2003 have relied on the exemption in the past and therefore should continue to receive it.

– *Request for Rehearing and Clarification of Reliant Energy, Inc* in FERC Docket No.s EL03-236-001, EL03-236-002, EL03-236-003, and PL04-2-000 (February 24, 2004 Reliant Complaint)

- PJM submits a compliance filing proposing eliminating the blanket exemption for post 1996 generating units from offer capping as directed by FERC in its January 25, 2005 order. The filing also includes Tariff revisions requiring that agreements for alternative price caps for frequently mitigated units be filed with the Commission for informational purposes only, and stating that they will become effective the day after such a filing is made.

– *PJM Interconnection LLC (Compliance Filing)* in FERC Docket EL03-236-005 (February 24, 2005 Filing)

July 5, 2005

- FERC order generally denying rehearing of the Commission's January 25, 2005 Order, but granting rehearing in part with respect to scarcity pricing, particularly with respect to the prices for units that are mitigated during scarcity conditions.

The Commission sets for rehearing whether mitigation prices need to be adjusted during scarcity conditions and allows parties to raise whether even in non-mitigated markets, scarcity pricing may be necessary.

– *Order on Rehearing, Clarification, and Compliance Filings, Establishing Further Hearing Procedures, and Consolidating Proceedings* 112 FERC ¶ 61,031 (July 5, 2005 Order)

August 4, 2005

- PJM submits compliance filing in response to the Commission's July 5, 2005 order. PJM proposes Tariff updates that allow a generator to deactivate if it notifies the Transmission Provider of its intent 90 days in advance, regardless of whether it would adversely affect system reliability. The revised Tariff also requires the Transmission Provider to give at least 30 days notice to the generator owner of the date where its operation is no longer needed for system reliability, and allows generators to recover project investment costs if PJM determines that the unit is no longer needed for reliability.

– *PJM Interconnection LLC* in FERC Docket EL03-236-008 (August 4, 2004 Filing)

August 31, 2005

- PJM submits for approval its Reliability Pricing Model, proposed as a replacement for its current capacity pricing model. The new RPM proposes valuing capacity by location and utilizing a downward sloping demand curve in annual auctions. The auctions would be for resources to be delivered four years later, with the four-year forward commitment allowing planned new generation and transmission upgrades to compete with existing generation to meet resource adequacy requirements. Higher prices would be paid to capacity resources with that can provide 30-minute reserves (quick start) and load-following capability. PJM further proposes explicit market power mitigation rules to address capacity market structure concerns.

– *PJM Interconnection LLC*, filed in Docket ER05-___-000 and EL05___-000 (August 31, 2004 Filing)

APPENDIX B: FERC ORDERS AND FILINGS RELATING TO ISO NEW ENGLAND LICAP PROPOSAL

September 20, 2002

- FERC accepts a new Standard Market Design (SMD) proposal for New England, which will replace the existing New England Power Pool (NEPOOL) market rules with the proposed Market Rule 1. Included in the SMD design is a *pro forma* reliability-must-run (RMR) agreement, which can be negotiated by ISO New England to help expensive, seldom run units recover high fixed and operating costs. To be eligible for an RMR contract, the unit must be necessary for reliability and the unit would be retired if no contract were approved. These requirements assume that most of these units are located in high congestion energy pockets known as designated congestion areas (DCAs), such as in Southwestern Connecticut.
- – *Order Accepting in Part and Modifying in Part Standard Market Design Filing and Dismissing Compliance Filing* 100 FERC ¶ 61,287 (September 20, 2002 Order)

December 20, 2002

- FERC grants in part and denies in part requests for rehearing of the Commission's September 20, 2002 Order and approves the new CT Proxy system proposed by the New England ISO. The proposal said that a CT Proxy price high enough to recover fixed costs may serve as a safe harbor bid during all hours for RMR units, and that that bids exceeding the CT Proxy will be subject to mitigation by the ISO. The Commission also reiterates ISO-NE's authority to negotiate RMR agreements to ensure system reliability, but cautions that the ISO must ensure that contracts are only negotiated with units that are needed to ensure reliability.
- – *Order Accepting Reliability Agreements* 101 FERC ¶ 61,341 (December 20, 2002 Order)

January 16, 2003

- PPL Wallingford LLC proposes an RMR cost-of-service agreement negotiated with ISO New England for four of its units located in Southwest Connecticut. The agreements allow PPL Wallingford to continue the operation of four generating units necessary for reliability on a cost-of-service basis. In exchange for keeping the four units operating, PPL Wallingford will receive a monthly fixed cost charge to help them cover the units' variable operation and maintenance costs. The payment will be calculated using an annual fixed revenue requirement (AFRR) of $30.7 million dollars for these four units, and will be subject to reduction based on PPL Wallingford's energy market revenue.
- – *Cost of Service Agreement Among PPL Wallingford Energy LLC, PPL EnergyPlus, LLC and ISO New England, Inc* in FERC Docket ER03-421-000 (January 16, 2003 Filing)

February 26, 2003

- Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, and NRG Power Marketing Inc submit RMR cost-of-service agreements negotiated with ISO New England. The filing explains that these four generating stations, which are necessary to maintain reliability throughout Connecticut, are located in DCAs in the Southwest portion of the state. The units are rarely dispatched in economic merit, and therefore have limited opportunities to recover their high operating costs. The proposed agreements would allow these units to bid up to a given safe harbor price, defined as the incremental operating cost of a hypothetical combustion turbine (CT) generator plus the unit's annual fixed costs, calculated based on expected number of operating hours for that year. The parties in the agreement believe that this safe harbor threshold will allow these units to more effectively recover their costs.

– *Reliability Agreements Among Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, NRG Power Marketing Inc., and ISO New England Inc.* in FERC Docket ER03-563-000 (February 26, 2003 Filing)

March 25, 2003

- FERC issues an order allowing ISO-NE to collect costs associated with the Reliability Projects described in the February 26, 2003 filing. The order allows ISO New England to disburse the funds to the generators involved in the agreements to ensure that they are adequately maintained for the summer peak season.

– *Order on Joint Emergency Motion* 102 FERC ¶ 61,314 (March 25, 2003 Order)

April 25, 2003

- FERC rejects Devon Power LLC et al's filed cost-of-service agreement (February 26, 2003 Filing) and permits the proposed contracts to recover only certain going-forward maintenance costs. The Commission says that expensive units under RMR agreements receive greater revenue than new market entrants, who are receiving suppressed revenues from the lower spot price resulting from existing RMR contracts. The Commission directs ISO New England to develop a market based mechanism to reduce the use of RMR contracts. In the interim, FERC suggests a system that would allow seldom run units to raise their bids to a Peaking Unit Safe Harbor (PUSH) limit, defined as the sum of its fixed and variable costs divided by the number of megawatt hours supplied in the previous year. FERC asserts that the PUSH bid system will help high cost, seldom run units necessary for reliability to recover their fixed costs through the energy market rather than through RMR contracts. The order also removes the previously approved CT Proxy system (December 20, 2002 Order).

– *Order Accepting, in Part, Requests for Reliability Must Run Contracts and Directing Temporary Bidding Rules* 103 FERC ¶ 61,082 (April 25, 2003 Order)

June 6, 2003

- FERC grants in part and denies in part New England ISO's request for a rehearing and/or clarification in response to its September 20, 2002 Order. FERC denies the request for a rehearing of its decision to allow ISO New England to designate DCAs, asserting that it is the existence of a load pocket and not the designation of a DCA that imposes costs and difficulties on the market. The Commission also reaffirms its approval of the PUSH bid system over a CT Proxy system for cost recovery for expensive, seldom run units.

– *Order on Rehearing and Accepting in Part and Rejecting in Part Compliance Filings* 103 FERC ¶ 61,304 (June 6, 2003 Order)

May 16, 2003

- FERC rejects a proposed reliability-must-run agreement submitted by PPL Wallingford (January 16, 2003 Filing) based on their findings regarding the Devon Power LLC RMR agreement detailed in its April 25, 2003 Order. FERC maintains that the PUSH bid system set forth in the Devon decision will allow higher prices during hours when demand approaches capacity limits through the market rather than through RMR agreements. The Commission argues that all generators, including PPL Wallingford, will receive these high prices, and this should help them to recover their costs.
- – *Order Rejecting Reliability Must Run Agreement* 103 FERC ¶ 61,185 (May 16, 2003 Order)

March 1, 2004

- ISO New England submits a filing in compliance with FERC's April 25, 2003 Order that proposes implementing locational or deliverability requirements in the installed capacity (ICAP) market. The proposal is a response to FERC's directive that ISO New England create a market-based mechanism that will reduce the need for RMR agreements. The proposed LICAP system seeks to reduce reliance on RMR agreements by both introducing a locational element into the capacity market and by replacing the existing vertical demand curve with one that is downward sloping. The ISO proposes that its LICAP system replace the PUSH bid system ordered by FERC in its April 25, 2003 Order, and that LICAP be implemented by ISO New England no later than June 1, 2004.
- – *Compliance Filing of ISO New England, Inc.; Devon Power LLC, et al* in FERC Docket ER03-563-030 (March 1, 2004 Filing)

June 2, 2004

- FERC agrees with two broad concepts in ISO New England's March 1, 2004 LICAP proposal: (1) it is appropriate to establish ICAP regions and (2) the use of a demand curve in the ICAP market is reasonable. However, the Commission expresses concern that the regions set by New England do not adequately reflect the need for infrastructure investment in some areas, especially in Southwestern Connecticut. To that end, the Commission suggests that Southwestern Connecticut be designated as a separate ICAP region. The Commission also requests more information regarding the parameters of the sloped demand curve that the ISO proposed, and orders that a public hearing be held to discuss the appropriate methodology for determining the parameters of the demand curve. The order also extends the use of the PUSH mechanism in New England until LICAP can be fully implemented.
- – *Order on Compliance Filings and Establishing Hearing Procedures* in FERC Dockets ER03-563-030 and EL04-102-000 (June 2, 2004 Order)

July 2, 2004

- ISO New England submits a compliance filing in accordance with FERC's June 2, 2004 Order that directed the ISO to address the designation of Southwest Connecticut as a separate load zone. The ISO's analysis supports the findings of the Commission that Southwest Connecticut should be a separate ICAP region and energy pricing zone for load, as differences in transmission constraints between this area and the rest of the state will likely lead to an ICAP price difference.

– *Compliance Filings of ISO New England, Inc.* in FERC Dockets ER03-563-039 and EL04-102-002 (July 2, 2004 Filing)

November 8, 2004

- FERC denies request for rehearing and denies in part and grants in part clarification of the June 2, 2004 Order in which the Commission agreed with two broad concepts of ISO New England's LICAP proposal (establishing ICAP regions and introducing a demand curve).

– *Order on Rehearing and Clarification* 109 FERC ¶ 61,154 (November 8, 2004 Rehearing Order)

- FERC issues an order accepting ISO New England's July 2, 2004 Filing, and amends the ISO's earlier LICAP proposal to include Southwest Connecticut as a separate ICAP region and energy pricing zone for load.

– *Order on Compliance Filing* 109 FERC ¶ 61,156 (November 8, 2004 Compliance Filing Order)

November 2004-February 2005

- FERC holds hearings before an Administration Law Judge as ordered in its June 2,2004 Order. These hearings are to litigate the appropriate methodology for determining transfer capacity limits and demand curve parameters to be used in each LICAP region.

March 23, 2005

- FERC denies request for rehearing and denies in part and grants in part requests for clarification of its November 8, 2004 Rehearing Order. The Commission reiterates that it is their goal to develop a market-based mechanism that allows generators necessary for reliability to recover their costs without reliance on RMR contracts. They order that under the LICAP mechanism, all generators, not merely new entrants, located in a given LICAP region should receive the same LICAP price.

– *Order on Rehearing and Clarification* in FERC Dockets ER03-563-047 and EL04-102-007 (March 23, 2005 Rehearing and Clarification Order)

- FERC denies requests for rehearing of its November 8, 2004 order that Southwest Connecticut be made a separate LICAP and energy load zone.

– *Order on Rehearing* in FERC Dockets ER03-563-048 and EL04-102-008 (March 23, 2005 Rehearing Order)

June 15, 2005

- Initial Decision issued by the Administration Law Judge in the LICAP procedure finds that the ISO New England Demand Curve proposal provides a just and reasonable method for compensating generators necessary for reliability as a whole. The Decision also finds that LICAP is a reasonable method for attracting and retaining the necessary infrastructure to assure long-term reliability at the lowest cost to consumers. In addition, the Administration Law Judge (ALJ) orders that appropriate reductions be made to the proposed LICAP payments to account for peak energy rents. The decision also asserts that the ISO's mitigation procedure is essential to successful LICAP implementation, and that the price setting system proposed by the ISO is appropriate. However, the ALJ rejects ISO

New England's proposal to base payments on availability during operating reserve shortages, saying that the ISO has not met its burden of showing that its current approach for determining ICAP payments is unjust and unreasonable such that it should be replaced with the shortage hour approach.

– *Initial Decision* 111 FERC ¶ 63,063 (Initial Decision)

June-July 2005

- The New England Congressional Delegation, Governors, and Attorney Generals from the six New England states send opposition letters to the Commission urging it to reject ISO New England's LICAP proposal. They express their concerns that LICAP will increase residential electricity costs, and that the "experimental and radical plan" proposed by the ISO may not result in new capacity infrastructure in New England. The Congressional Delegation includes a series of questions that they request be answered by the Commission regarding the ISO's LICAP proposal.

– Letter from the New England Congressional Delegation to FERC Chairman Kelliher in FERC Dockets EL04-112 and ER03-563

July 25, 2005

- FERC Chairman Kelliher issues responses to the opposition letters received from New England officials noting that he can not discuss the case in specific detail, but pointing out that there is a serious lack of sufficient capacity in selected portions of New England and that the current pricing policy is ineffective. Kelliher indicates that the Commission is preparing a response to the questions submitted by the Congressional Delegation.

– Letters from FERC Chairman Kelliher to New England Legislators and Congressional Delegations in FERC Dockets EL04-112 and ER03-563

August 9, 2005

- The New England Congressional Delegation requests that the Commission delay any decision on the New England LICAP proposal by one year in order to consider alternatives to the demand curve approach proposed by ISO New England.

– Letter from the New England Congressional Delegation to FERC Chairman Kelliher in FERC Docket EL04-112-000

August 10, 2005

- FERC orders that oral arguments in these proceedings will be held on September 20, 2005. It states that it cannot commit to issuing an order on the Initial Decision by September 15, 2005 as requested by ISO New England for a January 1, 2006 LICAP implementation date. The Commission orders that the implementation of the LICAP mechanism, if it proceeds, be delayed until no earlier than October 1, 2006.

– *Order Granting Oral Argument and Delaying Implementation of Locational Installed Capacity Mechanism* in FERC Docket ER03-563-030 (August 10, 2005 Order)

September 9, 2005

- Richard Blumenthal, Attorney General for the State of Connecticut, the Connecticut Office of Consumer Counsel, the Connecticut Municipal Electric Energy Cooperative, and the Connecticut Industrial Energy Consumers (jointly

"The Connecticut Representatives") file a request for clarification of FERC's August 10, 2005 order. The Connecticut Representatives request that FERC affirm its prior rulings that a separate load zone for Southwest Connecticut will not be implemented until and unless LICAP is implemented. The Connecticut Representatives request clarification based on FERC Commissioner Nora Mead Brownell's concurrence that suggested that a separate SWCT load zone will be implemented on January 1, 2006. The motion argues that implementing the separate zone prior to the implementation of LICAP will likely harm Connecticut energy consumers by raising prices unnecessarily, and that critical timing issues will arise if the separate zone and LICAP are not implemented at the same time.

– *Answer of the Connecticut Department of Public Utility Control, the Connecticut Office of Consumer Counsel, and Richard Blumenthal, Attorney General for the State of Connecticut to the ISO New England Inc.'s Motion for Clarification and Motion for Clarification* in FERC Docket ER03-563-030. (September 9, 2005 Connecticut Motion).

September 12, 2005

- Richard Blumenthal, Attorney General for the State of Connecticut, the Connecticut Office of Consumer Counsel, the Connecticut Municipal Electric Energy Cooperative, and the Connecticut Industrial Energy Consumers (jointly "The Connecticut Representatives") file a complaint requesting that FERC order an amendment to ISO New England's Market Rule 1. The Connecticut Representatives claim that the current "flawed patchwork of market and regulation design" cannot provide Connecticut energy consumers with fair and reasonable electricity prices. They ask that FERC order New England's Market Rule 1 to say that all generators deemed RMR units, or otherwise deemed necessary for reliability by the ISO, must apply for cost-of-service compensation agreements. The Connecticut Representatives say that the current combination of a competitive market, the PUSH bidding mechanism, and RMR contracts will cost Connecticut consumers approximately $1 billion dollars in the upcoming year.

– *Complaint Requesting Fast Track Processing and for Order to Amend ISO New England's Market Rule 1 with Regard to the Compensation of Electric Generation Facilities in Connecticut* in FERC Docket EL05-150-000 (September 12, 2005 Complaint).

September 13, 2005

- Commissions from two New England states, Massachusetts and Connecticut, jointly submit a proposed alternative to LICAP, called the New England Resource Adequacy Market (NERAM). They argue that NERAM, once fully developed, will ensure greater competition in the capacity market than LICAP, leading to just and reasonable capacity prices in New England. Unlike LICAP, NERAM does not have a locational aspect; rather, it presents a centralized, regional capacity market that supporters believe will result in lower prices for consumers. Another critical difference between NERAM and LICAP is NERAM's proposed annual auctions instead of LICAP's monthly auctions. These auctions would auction off capacity contracts three-years in advance of the delivery date, which NERAM's supporters believe would allow new market entrants to compete with existing generators to assure reasonable capacity prices. The NERAM proposal also includes a vertical demand curve in contrast to LICAP's sloped curve. Supporters of NERAM believe that the vertical curve will provide just and reasonable rates under the competition created by NERAM's market design. The NERAM market design also includes locational ancillary services and forward reserve markets, which supporters believe will produce higher compensation for resources in load pockets and eliminate the need for RMR agreements.

– *Statement in Support of the New England Resource Adequacy Market of the Massachusetts Department of Telecommunications and Energy, Connecticut Department of Public Utility Control, Connecticut Office of Consumer Counsel, New Hampshire Office of Consumer Advocate, Maine Public Advocate, NSTAR Electric and Gas Corporation, National Grid USA, Northeast Utilities Service Company on Behalf of The Connecticut Light and Power Company, Western Massachusetts Electric Company and Public Service Company of New Hampshire, Strategic Energy LLC, Associated Industries of Massachusetts, the Business Council of Fairfield County, and the Energy Consortium* in FERC Docket ER03-563-030. (Two State NERAM Support Statement)

September 13, 2005

- Commissions from four New England states, New Hampshire, Vermont, Rhode Island, and Maine, submit a proposed alternative to LICAP known as the New England Locational Resource Adequacy Market (NELRAM). Like the proposal submitted by Connecticut and Massachusetts, the NELRAM proponents advocate annual three-year lead-time auctions that NELRAM proponents claim will allow new market entrants to effectively compete with existing participants. NELRAM also includes the use of a locational forward reserve market, as incorporated in the NERAM proposal, to ensure long-term capacity availability. Unlike the NERAM proposal, however, NELRAM includes a locational pricing system for the entire capacity market, not just for forward reserves and ancillary services. NELRAM supporters say that a locational forward reserves market alone is not enough to send the proper price signals for market participants to build the correct amount of generation where it is needed. The developers of NELRAM also support investigating increasing the energy bid cap, explaining while they do not support eliminating the cap altogether, this investigation would be an important part of the overall NELRAM market design.

– *Four State Commissions Proposed Alternative to LICAP* in FERC Docket ER03-563-030. (NELRAM Proposal)

ATTACHMENT 3

ON AN "ENERGY ONLY" ELECTRICITY MARKET DESIGN FOR RESOURCE ADEQUACY

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On an “Energy Only” Electricity Market Design for Resource Adequacy

Contents

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An "energy only" market design could avoid the need for increasingly prescriptive regulations targeted at ensuring resource adequacy. Transparent scarcity pricing would create better incentives for both operations and investment. An improved electricity market design would not eliminate all need for regulatory prescriptions. However, it would change the nature of the remaining problems and allow for market-based approaches that would not overturn the market.

Introduction

Electricity resource adequacy programs often target the "missing money" problem. The missing money problem arises when occasional market price increases are limited by administrative actions such as price caps. By preventing prices from reaching high levels during times of relative scarcity, these administrative actions reduce the payments that could be applied towards the fixed operating costs of existing generation plants and the investment costs of new plants. The resulting missing money reduces the incentives to maintain plant or build new generation facilities. In the presence of a significant missing-money problem, alternative means appear necessary to complement the market and provide the payments deemed necessary to support an appropriate level of resource adequacy.

In the United States experience, resource adequacy programs designed to compensate for the missing money create in turn a new set of problems in market design. The resource adequacy approaches become increasingly detailed and increasingly prescriptive to the point of severing the connections between major investment decisions and energy market incentives. Consideration of these new unintended consequences prompts interest in seeking ways to operate an electricity market without any money missing. This interest in turn requires further specification of an "energy-only" market design and consideration of alternative modifications of such designs that would address underlying policy concerns without recreating the missing money problems. The reference in quotes emphasizes that the intent is not to create a completely unregulated market. Rather the intent is to eliminate prominent imperfections in the market design and thereby change the nature of the regulatory prescriptions to allow for market-based approaches that would not overturn the market. The purpose of the present paper is to highlight the critical conceptual features of such an energy-only market.

There is an analogy here to other contexts with regulatory policies to influence markets to achieve public purposes without prescribing the technology or investments. For example, in the control of sulfur emissions from coal burning power plants there has always been a tension between command-and-control approaches that dictated technological solutions such as requiring scrubbers on all plants versus market-based approaches like cap-and-trade programs for sulfur emission allowances. The market-based approach targeted the problem (e.g., total emissions) rather than dictating the solution (e.g., scrubbers). The technology prescriptive approach for controlling sulfur emissions would have created high costs and unintended consequences. The alternative market-based approach with tradable emission allowances provided lower costs and better incentives. A similar task in electricity markets would be to establish better market designs and more compatible market-based interventions. In an energy-only market, the potential problems and objectives would be different and the same resource adequacy policy prescriptions might not be required.[1]

Missing Money

The missing-money analysis begins with the load cycle over the day and the seasons.[2] Changing levels of generation supply matched with changing load levels produce volatile costs. These costs include a mixture of the direct variable costs of marginal generators, energy values for storage limited hydro facilities, the marginal value of incremental demand, and so on. At the margin, we refer to the opportunity cost as the cost of meeting an increment of demand by decreasing other load or increasing generation. If contemporaneous spot prices reflect these opportunity costs, these prices would provide market participants with strong incentives during periods of scarcity. During most periods, market prices would be at a relatively low level defined by the variable operating costs of mid-range or base load generating plants. However, in some periods prices would rise above the variable operating costs of peaking units that were running at capacity and would reflect scarcity under constrained capacity with the incremental value of demand defining the system opportunity cost.

Spot prices could be summarized over the year by a price duration curve depicting the cumulative number of hours when prices exceed a given level. As shown in Figure 1, under perfect dispatch generation would operate according to its variable cost of production. The most expensive peak generation (e.g., $85/MWh variable cost) would operate for relatively few hours. The payments in area **A** above the operating cost of $85 would be the returns to cover the fixed costs of the peak plant, including the investment cost needed to compensate new entrants.

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1 For a discussion of the objectives of resource adequacy programs, see James Bushnell, "Electric Resource Adequacy: Matching Policies and Goals," University of California Energy Institute, CSEM WP 146, August 2005.

2 The characterization as "missing money" comes from Roy Shanker. For example, see Roy J. Shanker, "Comments on Standard Market Design: Resource Adequacy Requirement," Federal Energy Regulatory Commission, Docket RM01-12-000, January 10, 2003.

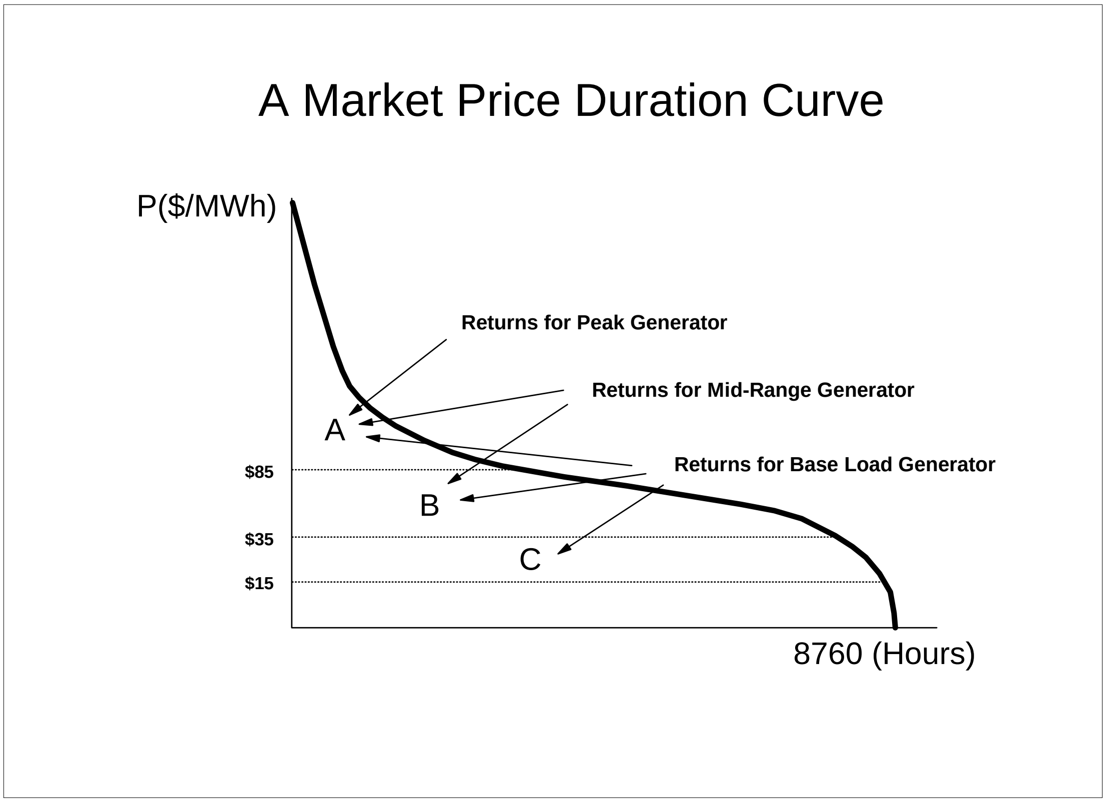

Figure 1

The mid-range generators (e.g., $35/MWh variable cost) would operate for many more hours, and the payments in area **A+B** would cover the larger fixed and investment costs of these plants. The lowest cost (e.g., $15/MWh variable cost) based-load generators would operate in virtually all hours but only rarely would the price fall to the lowest level. The combined area **A+B+C** would provide the payments for fixed and investment costs of base load generators.

The simplified graphic in Figure 1 illustrates the important point that in equilibrium the high prices during the peak hours provide part of the compensation needed for all generators, not just the peaking capacity. The magnitudes could be substantial. Although estimates vary, the approximate magnitude of area **A** would be on the order of $65,000/MW-year for a simple combustion turbine.[3] Hence, average peak prices of $1,000/MWh above operating cost would be needed sixty five hours a year in order to meet the payment requirements for peaking generation.

Introduction of administrative measures to limit the highest prices, such as through a price cap, would reduce payments available to all types of generating plants.

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[3] PJM, State of the Market Report 2004, March 8, 2005, p. 82. Estimates for New York city could be twice as high.

As shown in Figure 2, the price cap creates the "missing money." This is the payment to generation that is eliminated as a result of the curtailment of prices. The administrative rules that produce the missing money include a variety of procedures. Explicit price caps are not the usual means of restraining prices. A more likely constraint on generator revenues would arise from an offer cap on generators to mitigate market power. In principle, mitigation through an offer cap need not create missing money. However, when the offer cap combines with a pricing rule that spot prices must be set by the highest (mitigated) offer for any plant running, the result can be capped prices and missing money. The problem would arise when the pricing rule does not fully account for the opportunity cost of incremental demand or incremental operating reserves during periods of scarcity. These opportunity costs at the margin could result in prices above the offer cap.

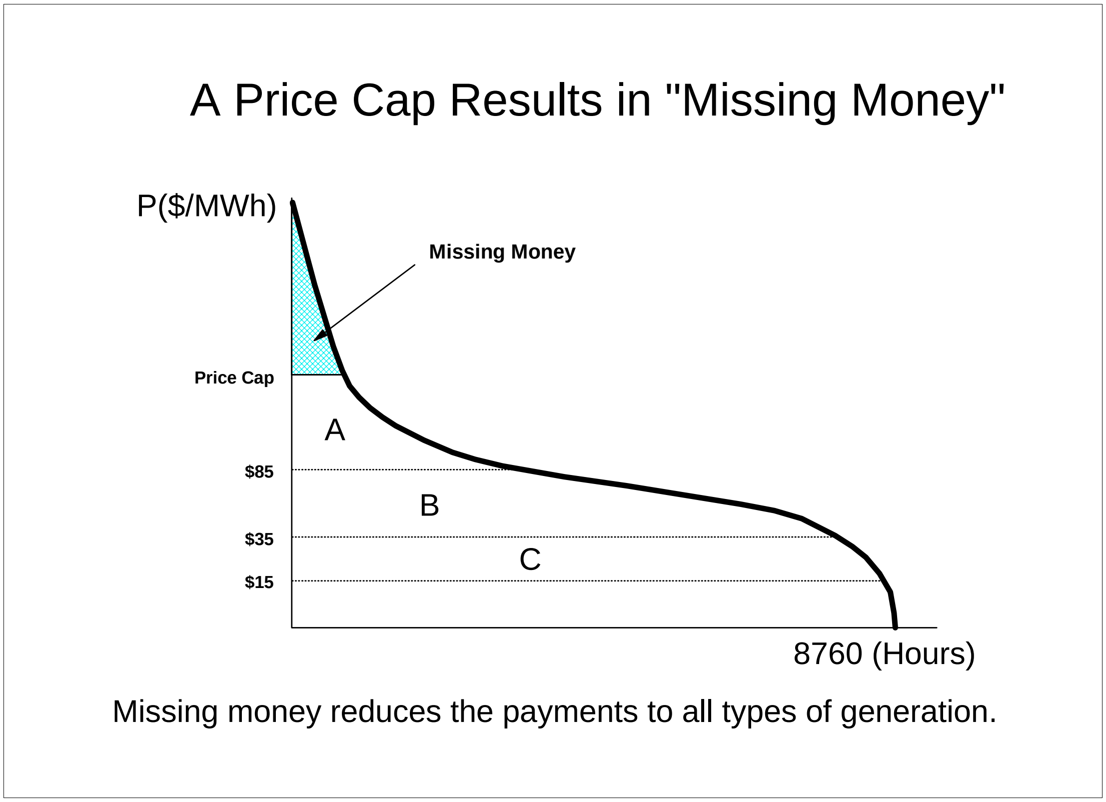

Figure 2

More indirect contributors to missing money would be reliability must run (RMR) units or out of market (OOM) dispatch, both of which involve use of expensive generating plants to meet load. However, various rules exclude these plants from consideration as part of the market and associated determination of prices. For example, the innovation of "soft" price caps institutionalized a device for keeping reported market prices low when real opportunity costs were higher. Collectively these rules produce the anomaly of constrained supplies and low prices.

The missing money goes hand-in-hand with "missing incentives." In the short run, the missing incentives complicate the task of the system operator in maintaining a secure dispatch. With prices disconnected from opportunity costs, market participants would have little incentive to act to enhance security and could face strong incentives to take actions, like leaning on the system to increase exports, which add to the security problems. A result is the need for ever more complicated rules to mandate behavior that is otherwise inconsistent with the incentives. As the rules mount up, the flexibility sought through markets can disappear. By now, it has been widely recognized that one of the principal advantages of locational marginal pricing systems is the alignment of participant incentives to support rather than oppose actions needed to manage congestion in the grid.[4] This role of reinforcing incentives to support reliability would be of greatest importance during periods of scarcity when the missing incentives arise.

The missing incentives extend to investment in new generation facilities or their substitutes. By some estimates the missing money amounts to a much as half or more of the $65,000/MW-yr payment required for new peak load generation investments.[5] It is this missing money that motivates interest in supplementary resource adequacy programs to provide a return to existing plants or support investment in new facilities. A direct approach to meeting the requirements of resource adequacy is to create a process beyond the energy market that provides added payments to generators who maintain or build needed generation facilities. Given an underlying assumption that administrative measures will necessarily be invoked to cap energy prices, and will always lead to insufficient payments in the energy market to maintain the desired level of capacity, the missing money leads inexorably to alternative approaches such as installed capacity (ICAP) requirements and related designs.[6]

The ICAP programs present a number of challenges.[7] For example, the assumption of a price-capped energy market implies that appropriate capacity choices must be identified by means other than market participants responding to the incentives provided through energy prices. This creates a need for central planning and greater prescription by regulators. Accordingly, regulators act on behalf of customers to take on more of the risks inherent in the long term investment decisions. When these details begin to emerge, participants recognize that this resource adequacy approach would recreate many of the features of electricity systems that were to be replaced by greater

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4 Phillip G. Harris, "Relationship between Competitive Power Markets and Grid Reliability: The PJM RTO Experience," Issue Papers on Reliability and Competition, US Department of Energy and Natural Resources Canada, August 2005, pp. 4-5. (www.energetics.com/meetings/reliability/papers.html)

5 Federal Energy Regulatory Commission, State of the Market Report, Washington DC, June 2005, p. 60.

6 For an extensive examination of this logic, see the workshops sponsored by the California Public Utility Commission, California Energy Commission and the California Independent System Operator at www.cpuc.ca.gov/static/industry/electric/installedcapacity/041004_instcapacity.htm. A summary of the arguments and subsequent recommendations appear in California Public Utility Commission, "Capacity Markets White Paper," Staff White Paper, CPUC Energy Division, August 25, 2005, (www.cpuc.ca.gov/word_pdf/REPORT/48884.pdf).

7 Scott M. Harvey, "ICAP Systems in the Northeast: Trends and Lessons," LECG, Report to the California ISO, September 2005.

reliance on restructured electricity markets. Inherent in this integrated planning process would be to shift a substantial portion of the investment risk and stranded costs back to customers who would be required to pay under the force of regulation.[8]

The usual argument that leads to this resurrection of integrated planning and regulatory driven investment begins with an assertion that the pure "energy only" electricity market behind Figure 1 is not politically feasible. If low price caps are imposed on the energy market, then something like a significant missing-money problem must follow. However, when the ICAP cure for the missing money problem starts to look worse than the disease, analysts of ICAP-type mechanisms revise this judgment and look more closely at a market design that does not breed the disease and hence does not require the cure.[9] This second look at an energy-only market design should not translate immediately into ignoring the underlying motivations for the administrative measures that constrain prices, such as the need to mitigate market power. But it would require refocusing attention on the policy ends and not the administrative means.

The ubiquitous reference to the missing-money problem found in resource adequacy proposals usually pays homage to the appeal of Figure 1 and the so-called "energy only" market. If only electricity prices could reach market-clearing levels defined by the opportunity costs, where there would be no administrative measures to cap prices and no missing money, there would be no need for administrative measures to supplement the payments to generators.[10] But if the highest spot prices would be too

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8 Bruce W. Radford, "Holes in the Market," Public Utilities Fortnightly, March 2005, pp. 19-21, 46-47.

9 For example, a series of workshops sponsored by the Public Utility Commission of Texas (PUCT) outlined this evolution of concern with installed capacity markets and return to interest in an energy-only approach. See www.puc.state.tx.us/rules/rulemake/24255/24255.cfm. A staff paper summarized many of the issues, Eric S. Schubert, "An Energy-Only Resource Adequacy Mechanism," Public Utility Commission of Texas, Staff White Paper, April 14, 2005. The staff subsequently recommended that the PUCT develop the details to "… provide for resource adequacy in ERCOT to be achieved through an energy only design." See Richard Greffe, Public Utility Commission of Texas, Wholesale Market Oversight, Memorandum, July 8, 2005. A similar direction appears in the Midwest Independent System Operator, "Discussion Paper on Resource Adequacy for the Midwest ISO Energy Markets," Draft, August 3, 2005.

10 Miles Bidwell, "Reliability Options," Electricity Journal, Vol. 18, Issue 5, June 2005, pp. 1. Eugene Meehan, Chantale LaCasse, Phillip Kalmus, and Bernard Neenan, "Central Resource Adequacy Markets for PJM, NY-ISO, and NE-ISO," NERA Final Report, New York, February 2003. Shmuel Oren, "Capacity Payments and Supply Adequacy in Competitive Markets," VII Symposium of Specialists in Electric Operational Systems Planning," Basil, May 2000. Shmuel Oren, "Ensuring Generation Adequacy in Competitive Electricity Markets," University of California at Berkeley, April 2004. Shmuel Oren, "Capacity Mechanisms for Generation Adequacy Insurance," CPUC-CEOB-CAISO Installed Capacity Conference, San Francisco, California, October 4-5, 2004. Roy J. Shanker, "Comments on Standard Market Design: Resource Adequacy Requirement," Federal Energy Regulatory Commission, Docket RM01-12-000, January 10, 2003. See also Roy J. Shanker, "Comments," Federal Energy Regulatory Commission Technical Conference on Capacity Markets in the PJM Region, June 16, 2005. Harry Singh, Call Options for Energy: A Market Based Alternative to ICAP and Energy Price Caps," PG&E National Energy Group, October 16, 2000. Steven Stoft, Testimony on Behalf of ISO New England on Locational Installed Capacity Market Proposal, Submitted to Federal Energy Regulatory Commission, Docket Number ER03-563-030; Direct August 31, 2004; Supplemental November 4, 2004; Rebuttal February 10, 2005. Carlos Vázquez, Michel Rivier, and Ignacio J. Pérez-Arriaga, "A Market Approach to Long-Term Security

high, so the argument goes, the exposure of customers would be unacceptable and the energy-only market could never work. Typically, the design of an energy-only market is dismissed without further consideration.[11] The discussion of an energy-only market ends there, and attention turns to ICAP design in its many forms.

When frustration with the implications of ICAP markets sets in, the possibility arises to give more serious attention to how an "energy only" market might operate and what would be needed to make the transition. To revisit this issue and consider the ends rather than the means requires a greater specification of such a market in order to understand what would be included in the basic elements and what problems might remain that could motivate an interest in modifications of an energy-only market approach to resource adequacy.

Energy-only Market Design

There are many appeals to an idealized vision of an energy-only market, but there is little description of the key features. The assumptions of the idealized vision do not describe real systems. For example, high spot prices raise the specter of market power, and it is difficult to step back from this reality and describe a market without the exercise of market power. Hence, the discussion of design elements quickly detours from consideration of the core features of an idealized energy-only market. The intent here is to avoid this detour long enough to sketch out the principal elements. The discussion here assumes competitive behavior and no transaction costs, but returns to these issues later in discussing potential problems with an "energy-only" market design.

A core idea of an electricity market that relies on market incentives for investment is that these incentives appear through the largely voluntary interactions of the participants in the market. A main feature of the market would be prices determined without either administrative price caps or other interventions that would depress prices below high opportunity costs and leave money missing. The real-time prices of electric energy, and participant actions, including contracting and other hedging strategies in anticipation of these prices, would be the primary drivers of decisions in the market. The principal investment decisions would be made by market participants, and this decentralized process would improve innovation and efficiency. A goal would be to avoid repeating the problem of leaving customers with stranded costs arising from decisions in which the customers had no choice. This change in the investment decision process and the associated reallocation of risks would arguably be the most important benefit that could justify greater reliance on markets and the costs of electricity restructuring. If this were not true, and if it would be easy for planners and regulators to

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of Supply," IEEE Transactions on Power Systems, Vol. 17, No. 2, May 2002. Carlos Vázquez, Carlos Battle, Michel Rivier, and Ignacio J. Pérez-Arriaga, "Security of Supply in the Dutch Electricity Market: the Role of Reliability Options," Report IIT-03-084IC, Comillas, Universidad Pontifica, Madrid, Draft Version 3.0, Madrid, December 15, 2003.

[11] "Energy-only" markets of different designs exist in Alberta, Australia, New Zealand and Europe. The lessons there are relevant, and the resource adequacy issue is not fully resolved. However, the differences in context and details would take the discussion further afield from the U.S. setting.

lay out the trajectory of needed investment for the best portfolio of generation, transmission and demand alternatives, then electricity restructuring would not be needed.

A central concern of the growing doubts about the direction of development in administrative installed capacity markets is the loss of this critical reallocation of decisions away from regulators and towards market participants. The increasing scope, increasing detail and increasingly longer horizons of ICAP programs establish an evolutionary path with no end in sight.[12] It is not the capacity construct *per se* that should be of concern. For example, operating reserve capacity requirements are an essential part of electricity systems. Rather it is the scope, duration and detail of mandatory ICAP obligations that are imposed by the central planner, and the corresponding shift of the locus of investment risks decisions away from the market with the decisions made under the central plan and the risks assigned back to captive consumers.

The changes reverberate through the market design, transforming the original role of the system coordinators, the Independent System Operator (ISO) or Regional Transmission Organization (RTO): "the ISOs/RTOs are not *principals* ***in*** *the market* but rather *service providers* ***to*** *the market*. … Creating a forward looking capacity construct is therefore potentially not 'just' an incremental increase in responsibilities for an ISO or RTO; but rather it is a significant structural change to the role they currently perform."[13] In effect, the effort to compensate for capped spot prices recreates the regulatory integrated resource planning process that was to be replaced by more decentralized market decisions. This movement to create centralized investment decisions according to long-term requirements set by the ISO follows directly from the missing incentives of the price-capped energy market. Hence, any effort to support market decisions and avoid mission creep at the ISO must then provide the missing incentives through market-based prices rather than administrative substitutes. An essential feature of an energy-only market design would be efficient spot pricing to reflect opportunity costs.

Just as important as embracing market-driven spot pricing is a recognition that an energy-only market does not assume or require that all transactions be limited to the spot market. To the contrary, a robust energy market with realistic real-time prices would permit and encourage long-term contracting of a variety of forms to reflect the conditions and relative risk preferences of the market participants. The major economic decisions surrounding investment and most of the actual transactions might and could be made with long-term contracts voluntarily arranged by the parties. Market participants might choose voluntarily to enter into ICAP type contracts, but this would be only one of the possible contract forms. However, even if spot-market transactions were reduced to a small volume for balancing and congestion management, expectations regarding future spot prices created by uncapped energy pricing in the spot market would be essential and would be reflected in the terms of forward contracts.

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[12] Craig Hart, "Capacity Markets: A Bridge to Recovery?", Public Utilities Fortnightly, May 2005, pp. 24-27.

[13] Midwest Independent System Operator, "Discussion Paper on Resource Adequacy for the Midwest ISO Energy Markets," (emphasis in the original), Draft, August 3, 2005, pp. 1-2.

Similarly, the emphasis on an "energy only" market does not mean that there would be nothing but spot deliveries of electric energy with a complete absence of administrative features in the market. Since the technology of electricity systems does not yet allow for operations dictated solely by market transactions with simple well-defined property rights, the system requires some rules to deal with the complex interactions in the network. To the contrary, there would of necessity be an array of ancillary services and associated administrative rules for such services. For instance, the existing technology for electricity requires that system security be met by providing operating reserves in generation in order to meet the possible contingencies. The required level and configuration of these operating reserves are not determined in a market. The operating reserve requirements are based on prior studies and experience of what resources would be needed and where they would be needed over the next minutes or hours of the dispatch in order to protect against both involuntary load shedding and more serious dangers of system collapse.

Other examples include the rules for providing contingency security constraints for transmission, and various ancillary services that are inherently administrative, even though they may be designed with an economic component included. The goal of the energy-only market is not to eliminate all administrative rules. Rather a goal is to design the rules, pricing and implied incentives to support operating and investment decisions made by market participants in response to the forces in the market.

In the discussion below, the emphasis is on providing electric energy with the critical operating reserves as the representative ancillary service. For the initial discussion, it is assumed that there are no locational issues and the design sketch applies as though everything occurred at a single location. The discussion illustrates the principles that would apply to implementation in a network with transmission constraints and locational requirements.

Demand

The energy-only market begins with the real-time demand for energy in the wholesale market. In order to capture some of the features of the real system, the demand for electricity shown in Figure 3 divides into two segments. The inflexible demand represents the customers that are assumed not to have individual real-time meters or real-time individual controls. It is not possible for these customers to receive or respond to the incentives provided by real-time prices. Typically these customers pay a fixed price over the period, here assumed to be $30/MWh. Of course, these customers have some implicit demand curve and the load that results at $30 is the load assumed to apply no matter what the spot market conditions.

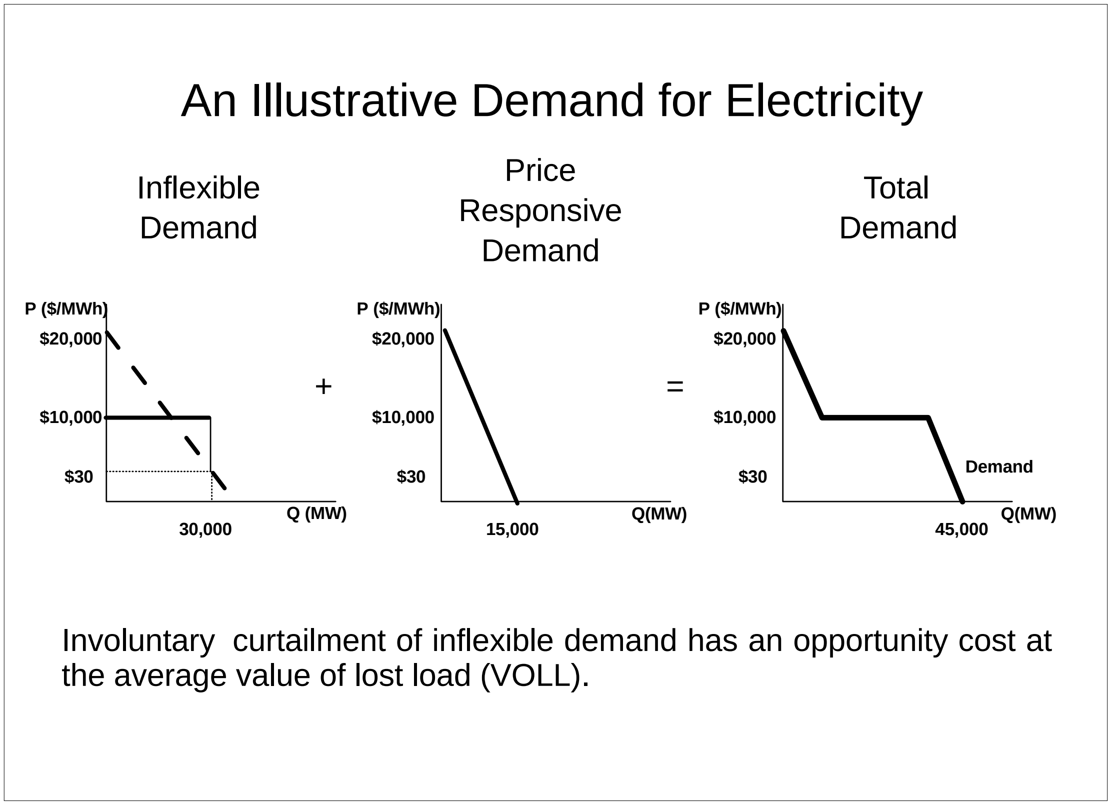

Figure 3

Inflexible demand would maintain this load level unless conditions became severe enough that the system operator must intervene. In this event there would be involuntary curtailment through rolling blackouts or brownouts. The simplifying assumption for the illustration is that the lack of metering and individual controls limits the system operator to random, or at least proportional reductions of inflexible loads. The individual inflexible customers could not be dispatched or metered separately, but the load of the group could be reduced by curtailing all the loads proportionally. Since the price the customers will be paying may still be $30/MWh, this would perforce be involuntary curtailment. The average opportunity cost of the involuntary curtailment would be the average "value of the lost load" (VOLL) defined by the implicit demand curve, which represents the correct estimate of the cost of curtailment given the limits on control of inflexible load. This average VOLL is assumed to be $10,000/MWh in the example. Of course, some of these customers would be willing to pay more, but some who are curtailed would also be prepared to be curtailed for much less than the average opportunity cost. Under the circumstances, the marginal cost of curtailment for the inflexible group is the average cost of the involuntary curtailment, $10,000/MWh.[14]

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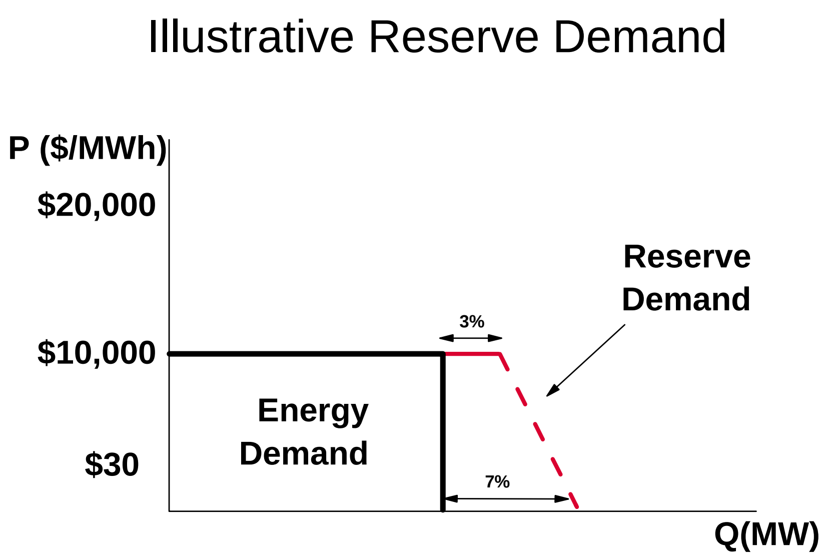
[14] Steven Stoft, Power System Economics, IEEE Press, 2002, p. 149-150.

Who provides this estimate of average VOLL? Absent some means of credible declaration by the customers, this implicit demand curve would be estimated by regulators or by the system operator. Hence, there would be an administrative determination of what should serve as the average VOLL. This average VOLL price and the proportional curtailment in effect convert the implicit demand curve of the inflexible load into a horizontal demand curve as shown in the left panel in Figure 3.

By contrast, the flexible load would have appropriate metering and control. The control might arise through the dispatch actions of the system operator or through the decentralized choices of the loads given their estimate of prices. These flexible customers would be able to bid demand in real-time and follow signals to reduce or increase load when prices were high or low. This demand curve would arrive naturally through the bids or choices of the load, and would require no further determination by the system operator. The combination of the two demand curves through horizontal addition as illustrated in Figure 3 results in the demand for the electricity to be delivered to the customers.



There is a minimum level of operating reserve (e.g., 3%) to protect against system-wide failure. Above the minimum reserve, reductions below a nominal reserve target (e.g., 7%) are price senstive.

Figure 4

A characterization of electric energy demand would not complete the demand story. In addition to the electric load at any moment, the system operator must obtain an appropriate level of operating reserves. For instance, Figure 4 illustrates operating reserves determined according to two rules that would combine to provide a reserve demand curve in this energy-only market. To isolate the reserve demand curve, take the level of energy demand as fixed. First assume there is a minimum level of reserve, set here at 3%. The criteria for determining this minimum requirement would be an issue, but is not the point of the discussion here. The constraint could be taken directly from established minimum reserve requirements set by the North American Electric Reliability Council (NERC). Some minimum is needed, for example, to prevent catastrophic failure through a widespread and uncontrolled blackout in the system. The exact level is not important for the illustration, and we return to this issue later. What is important for the energy-only market design is that this minimum level conforms to the actions of the system operator. The system operator would not go below this level of reserves even if this required involuntary curtailment of inflexible load. This level of operating reserves is shown as the solid red line in Figure 4.

Above this minimum level of operating reserves, there would be more flexibility. Other things being equal, it would be better to have more operating reserves. But if energy demand increased the operator would not impose involuntary curtailments in order to maintain a higher level of operating reserve. Under the traditional system, a system operator would reduce operating reserves and turn to load shedding only as a last resort. To do otherwise would be to impose involuntary load shedding with certainty in order to avoid a contingent probability that involuntary load shedding might be required. Hence, recognizing that there is some flexibility in operating reserves is nothing new. What would be different than the traditional approach would be to identify the cost of reduced reserves. [15]

This would provide the second piece of the operating reserve demand. There is a tradeoff that would consider the marginal change in the expected loss of load, valued at the average VOLL, to define the willingness to pay for incremental reserves. Beyond the minimum level of reserves there would be a nominal reserve target, which for the illustration in Figure 4 reaches 7% of capacity above load if the reserves were free. However, at reserve levels above the minimum requirement the operator would not be willing to institute involuntary load curtailments and would instead accept operating reserve levels less than the target level if load were high and reserves were not freely available and free. In this range, as reserves levels approached the minimum level, the price would be increasing for operating capacity needed to meet energy load plus reserves. This is the price sensitive part of the operating reserve demand illustrated by the dashed red line.[16]

Setting operating reserve schedules over the next minutes or hours is a regular activity of system operators. Since the configuration of load and installed generation would already be known or relatively easy to predict, the task of scheduling suitable

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[15] Steven Stoft, Power System Economics, IEEE Press, 2002. p. 112-113.

[16] The reserve price would be the energy price net of avoided costs plus any spinning costs. There would be an interaction between the demand for energy and the demand for operating reserves. Strictly speaking, therefore, the simplified graphic with the dashed line captures the effect of reserve demand on energy price in the simultaneous clearing of energy and reserve markets.

operating reserves requires much less information than would parallel attempts to specify required installed capacity many months or years in advance. For operating reserves, there would be substantially less uncertainty and the dispatch could be updated quickly as conditions change. This is a familiar exercise for system operators. Equally familiar is the practice of accepting lower reserve levels during periods of generation scarcity relative to load requirements.

Less familiar would be the practice of translating these reduced reserve levels under increased scarcity into economic terms to reflect the implied higher opportunity costs. [17] Although reserve demand curves have been implemented by the NYISO, the experience with explicit demand curves linked to high average VOLL is limited. This additional step to price reserves according to a reserve demand curve would be included as part of implementation of the energy-only market sketched here. The reserve demand curve would be made explicit and included as part of the simultaneous implementation of the energy and reserve dispatch.

The absence of an appropriate operating reserve demand curve is one of the difficulties in market designs that result in *de facto* price caps and missing money. With little explicit energy demand bidding and no recognition of an operating reserve demand curve, the pricing rules default to the most expensive generator offer. With mitigated offers, this can result in a generator running at capacity and price being set at the variable cost with no scarcity rent, even when reserves are reduced. A reserve demand curve would improve the determination of prices in these scarcity conditions. However, if the reserve demand curve does not raise prices towards the average VOLL when operating reserve levels approach the minimum reserve level, then the demand curve is not capable of representing the effects of scarcity or capturing the true opportunity cost at the margin. If the pricing algorithms do not incorporate a demand effect, whether through participants' energy demand bids or through the simultaneous interaction with the operating reserve demand curve, the resulting price determination would be flawed in the periods of scarcity when it would be needed the most. If the price is always set at the running cost of the most expensive generator included in the dispatch, then either there is never any time when capacity is constrained or the pricing calculation is based on a misunderstanding of the meaning of short-run opportunity cost. The operating cost of the most expensive unit running is relevant when there is excess capacity. However, when capacity is short and generation supply is in effect fixed over the range, the demand curve for energy and operating reserve should set the price, and should be able to set the scarcity price at a high level.

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[17] Steven Stoft, Power System Economics, IEEE Press, 2002. pp. 197-200.

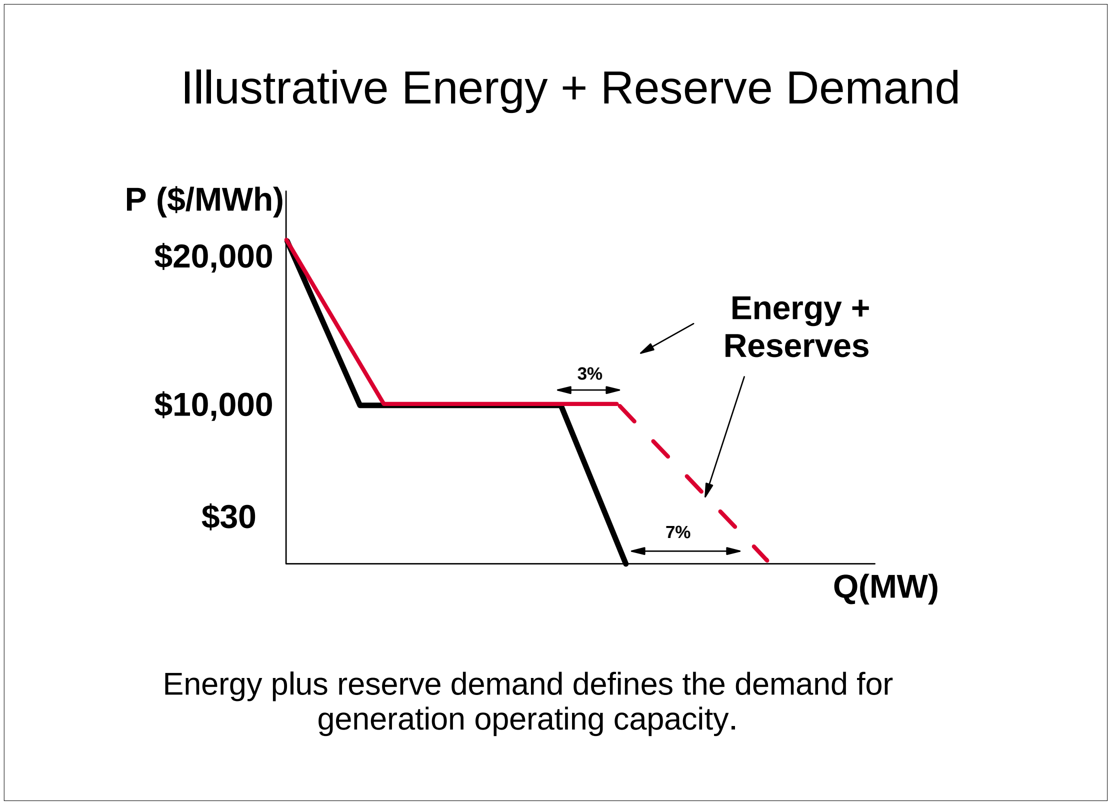

Figure 5

This price sensitivity for operating reserves provides an added slope for operating capacity demand between the minimum requirement and nominal target. When combined with the price sensitive energy demand, Figure 5 summarizes the total demand for energy and reserves. As the market tightens relative to available supply, reserves would be reduced and prices for energy and reserves would rise. When operating reserves reach the minimum level, the price reaches the $10,000/MWh average VOLL and involuntary load curtailments would be required

Supply and Pricing

On the supply side, the system operator would receive offers of available generating capacity with prices for energy and reserves. The system operator would use the load bids and generator offers to determine a bid-based, security constrained, economic dispatch (with locational prices) in the usual way. This would include both bilateral schedules and spot market imbalances priced at the equilibrium market price. During normal operating conditions with moderate load and a high degree of available generating capacity, the system operator would obtain the market equilibrium for energy at a relatively low price. Operating reserves would be well above the minimum level. This equilibrium condition is illustrated in Figure 6. All loads and all generation would clear imbalances at these energy prices. All generators providing operating reserves would be paid the market-clearing price for reserves at the energy price less the avoided variable costs of generation. Under the assumed design here, operating reserve requirements would not be attributable to individual customers, and all loads would be charged a contemporaneous uplift payment to cover the cost of operating reserves and other ancillary services.

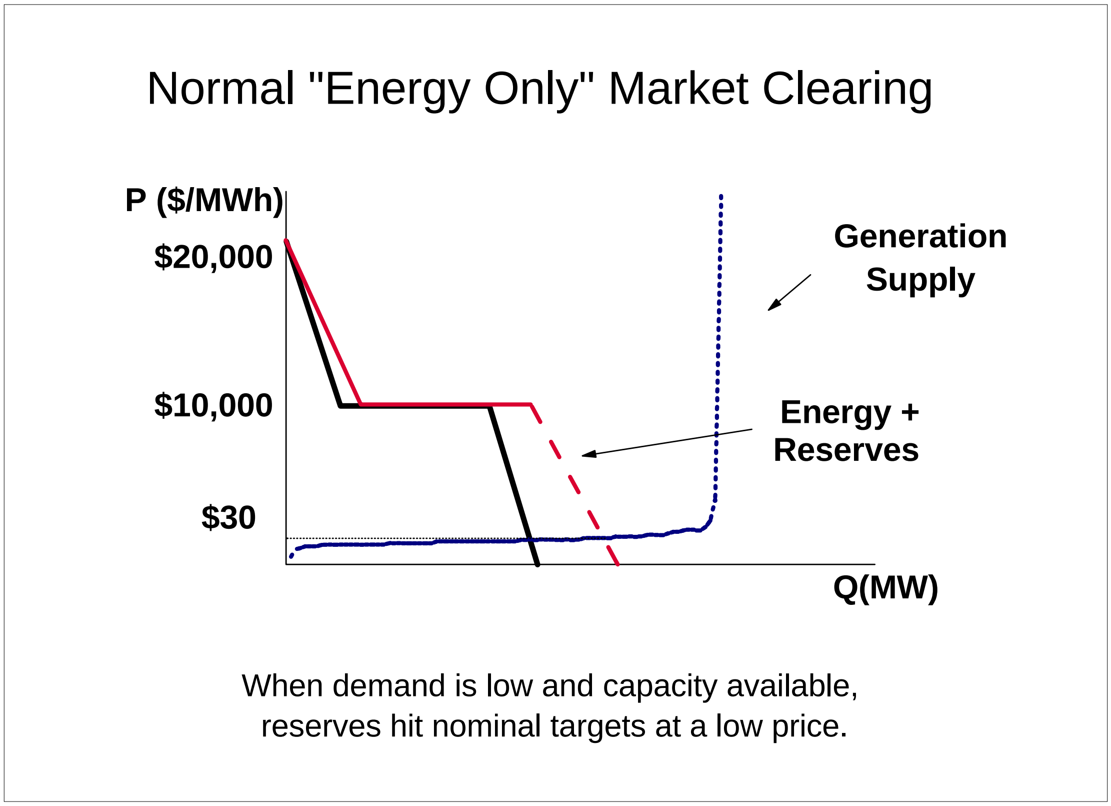

Figure 6

Under stressed conditions there would not be adequate capacity to meet all load and maintain the target nominal level of reserves. This would give rise to scarcity pricing determined by the capacities of the generation offered, the energy demand, and the administrative demand for operating reserves. As shown in Figure 7, the resulting price would be high, here illustrated as $7,000/MWh for energy and essentially the same market-clearing price for operating reserves. This would approach the average VOLL. Flexible customers with real-time metering would respond to the high price signals by reducing load. The system operator would make the decisions to reduce the level of operating reserves. The resulting equilibrium prices again would apply to all imbalances relative to bilateral schedules. Payments for operating reserves would be made to generators providing reserves and the cost would be applied to loads in a proportional uplift payment. All generators providing energy would receive the high energy price. All generators providing reserves would receive this high energy price less the variable cost of the marginal reserve capacity. Although scarcity conditions with very high prices would apply in relatively few hours, the payments to generators during these hours would include a large fraction of the total contribution to fixed and investment costs.

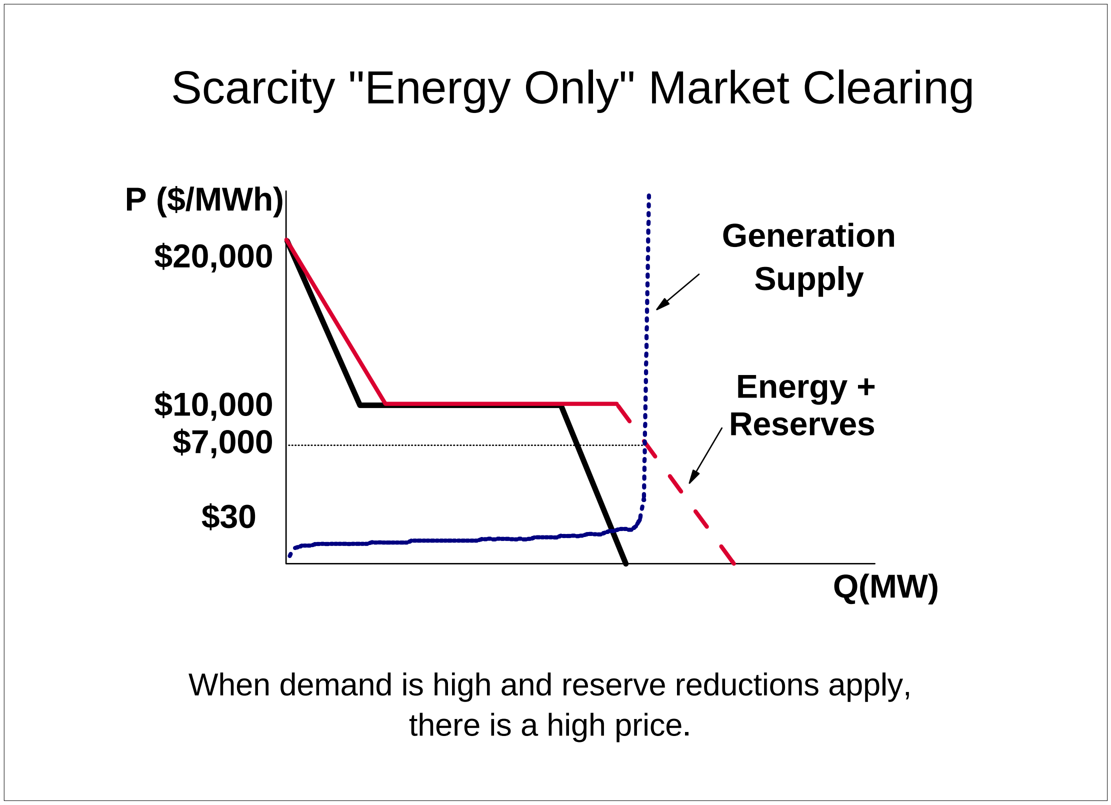

Figure 7

High energy prices during scarcity conditions would approach the average VOLL. If the degree of scarcity reaches the point that reserves are reduced to the minimum operating level, the system operator would turn to random or rotating involuntary load curtailments for the inflexible load. Under these conditions the price of energy would be at the average VOLL, with a corresponding price of reserves. This would continue over the full range of the inflexible load indicated by the horizontal segment of the demand curve in Figure 8. Customers with very high valuations (those above the average VOLL) would have the ability and the incentive to install the meters and controls allowing for real-time pricing to ensure they were not included as inflexible load. Thus the system could produce higher reliability levels for those who would be willing to pay above the average VOLL. However, except when *all* inflexible load would be curtailed, the equilibrium price would not rise above the administratively determined average VOLL. In real systems, curtailing all inflexible load with resulting prices going above the average VOLL would be highly unlikely.

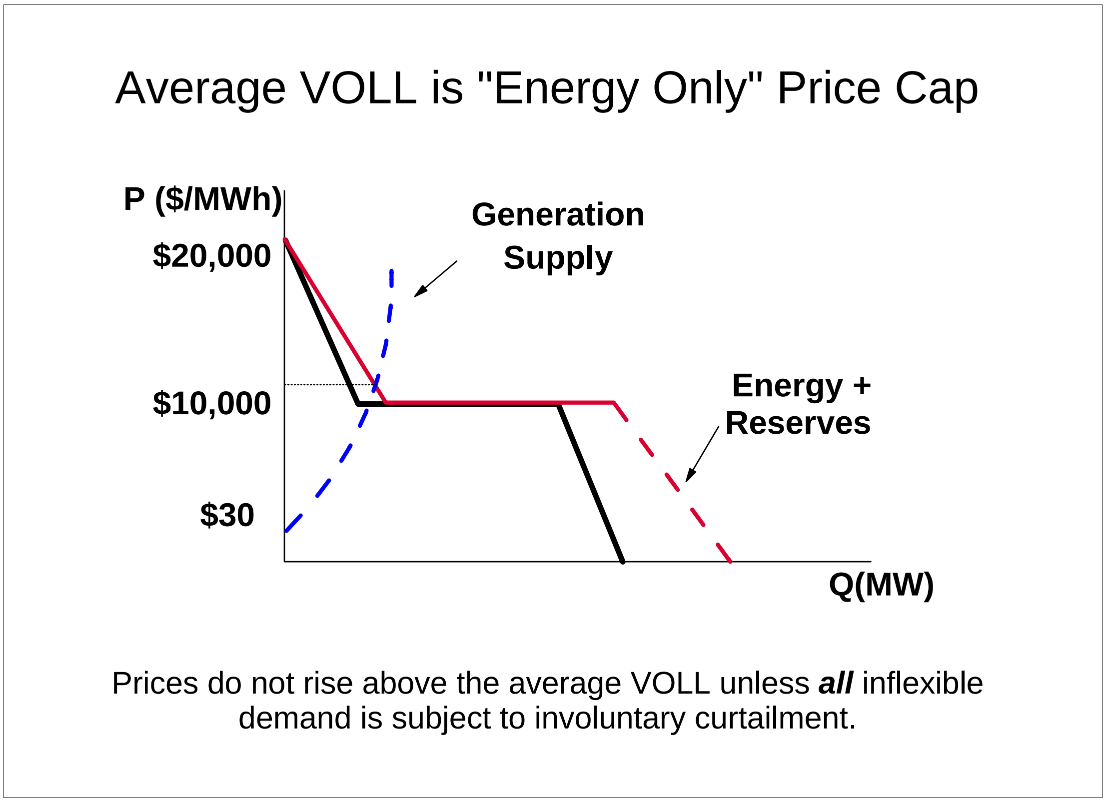

Figure 8

In this sense, it might be natural to refer to the average VOLL as a price cap. Although this is true in the sense of a prediction, it is worthwhile to emphasize that this would not be a price cap in the usual meaning. As discussed above, the average VOLL is the proper measure of the opportunity costs of the involuntary curtailments. Unlike with the usual price cap at a low price, the system operator would not have any offers for generation above this price that should be accepted. There would be no room for and no need for OOM purchases in their many forms to obtain additional energy or to reduce other load in order to avoid the involuntary curtailment. The average VOLL would set the appropriate market price when involuntary load curtailments were required.

The emphasis on connecting the energy and operating reserve demand curves to the average VOLL is not to ensure that this price will be reached often or that curtailments of inflexible load would be common. With an appropriate implementation of the operating reserve demand curve, the opposite would be true. Prices should be higher than in the capped market, but should seldom rise to the level of the average VOLL. The response in the market would obtain more demand response and investment in new capacity. It is the intermediate price responsive segment of the demand curve that would be important, and the connection to the average VOLL provides the anchor at the high end.

With the expected range of supply and demand conditions spanned by the illustration in Figure 6 and Figure 7, the “energy-only” market should produce a distribution of prices as illustrated in Figure 1. In long-run equilibrium, there would be no missing money. Market prices would provide the needed incentives for loads and generation. All loads and generators would settle imbalances relative to bilateral schedules at the market equilibrium price. Prices would at times be volatile, varying substantially over the day and over the seasons. For some hours, prices would be very high.

The anticipation of these uncertain and sometimes high prices would create strong incentives for market participants to contract forward. Under the idealized assumption of no transaction costs, contracts would arise to cover a substantial portion of all load and generation. The precise terms and prices embedded in these contracts would be determined according to the preferences of the market participants. In principle, neither the system operator nor the regulators need observe these contracts nor approve the terms.

Since there would be no missing incentives, there would be no need to devise operating rules to compel competitive actors to act against the incentives they face. Since there would be no missing money, there would be no need for resource adequacy programs designed to provide the missing money. Both generators and loads would be hedged through the forward contracts. Hence, there would be limited exposure to the volatile spot prices. These volatile prices and the price duration curve in Figure 1 would be critical to success of the energy-only market, but the limited exposure to high prices should not provide a critical mass of political pressure to induce further intervention in the market.

Energy-only Market in a Network

The simple energy market depicted in Figure 6 and Figure 7 illustrates the ideas in the context of a single period at a single location. The real system would involve many locations connected by a network and multiple periods. The resulting design would have the now familiar core features of the organized RTO markets.[18] The centerpiece would be a spot market organized as a bid-based, security-constrained economic dispatch with locational (nodal) prices as in Figure 9. The energy-only market includes bilateral schedules at the difference in the locational prices. Transmission hedges appear in the form of financial transmission rights designed congestion revenue rights (CRRs).

[18] See the CAISO Market Redesign and Technology Upgrade Program (MRTU), www.caiso.com/docs/2001/12/21/2001122108490719681.html.

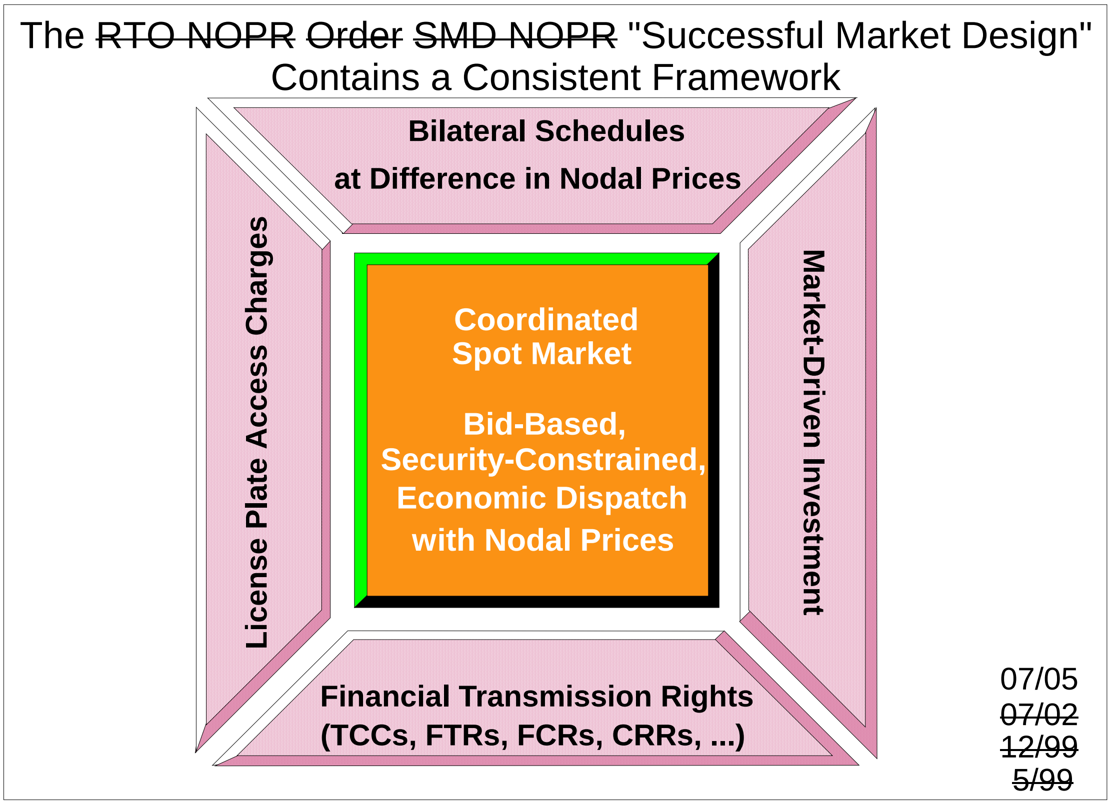

Figure 9

The real-time market could be combined with one or more forward markets such as the day-ahead market (DAM) with the same basic structure supplemented with virtual bids and schedules relative to the real-time market. This day-ahead market could include both a dispatch and a unit commitment process.

As is common, the unit commitment could be supported further by a reliability unit commitment (RUC) process in which the system operator’s day ahead forecast would be checked and additional units committed as needed to ensure reliability. The RUC units would receive a bid-cost guarantee if the realized revenues in the energy market were not as large as the bid costs. The RUC is an example of a largely non-market administrative rule driven by reliability requirements but structured in a way to support the remainder of the energy market. The RUC would not involve forward procurement of energy beyond minimum output levels, and hence would not undermine the incentives in the DAM. The same arguments and rules that apply in the current RUC implementations would carry over in the energy-only market design.

The requirements for operating reserves, expressed as location specific operating reserve demand curves, would apply as is now done in the RTO markets. Typically there would be some regional aggregation at a greater level than the individual nodes, and operating reserves must meet certain requirements in that region. Hence, congestion management would require finer nodal specification and pricing, and there would be a different set of aggregation rules for different types of operating reserves. Although the resulting model does not lend itself to the simple graphical addition of demand curves in the stylized illustrations above, there is nothing unusual about including operating reserves in the model with the appropriate mix of aggregation and rules that link reserves to nodal load and generation activities in a network. The resulting locational energy and reserve prices would be obtained through simultaneous optimization of energy and reserve dispatch with pricing to minimize the reliance on uplift payments.[19] The main innovations of the energy-only market design would be in the configuration of the reserve demand curves, connection to the average VOLL, and elimination of *de facto* price caps. In addition, this should eliminate the need for most or all OOM purchases.

Energy-only Market Defects

The outline of an energy-only market, with the necessary administrative rules structured to support market decisions, would raise concerns with regulators and others regarding its promise of providing efficient results and adequate investment. To some analysts the absence of the missing money problem might signal the presence of other market design defects. Further, since the idealized assumptions would not hold exactly in a real system, potential problems could undermine the workability of any attempt to approximate an energy-only market. Here we consider first issues like demand response, reliability and missing markets that could be addressed in principle within the energy-only framework. Market power would be more difficult to mitigate without regulatory intervention, but it is possible to design compatible regulatory interventions that would not disrupt basic operation of the market. A difficult problem would be a lack of forward contracting given both transaction costs for customers and regulatory rules that limit the incentives of load serving entities. A concern with inadequate contracting touches directly on the resource adequacy issues associated with the missing money problem.

Demand Response

The generic demand characterization in Figure 3 includes flexible load that responds to price. A conclusion might follow that an energy-only market would require a substantial degree of formal bidding for dispatchable energy that a system operator could use to respond to scarcity conditions. If there were little or no flexible loads, then prices would bounce between the low operating costs of generators and the high average VOLL. Hence, there is often an assumption that substantial energy demand response would be a prerequisite of an energy-only market implementation.

It is a commonplace that electricity markets would work better with more demand response. This is true of the energy-only market design just as it is true in a price-capped design. Under an energy-only approach there would be more, perhaps much more, incentive for load to acquire the necessary meters and take action to reduce demand during periods of scarcity and the associated high prices. However, despite the benefits, greater demand bidding is not a prerequisite of an energy-only market design.

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[19] William W. Hogan and Brendan J. Ring, "On Minimum-Uplift Pricing For Electricity Markets," Center for Business and Government, Harvard University, March 19, 2003, (www.whogan.com) .

Strictly speaking, for successful operation of market clearing it would not be necessary that load formally bid into the dispatch. With regular calculation and publication of locational prices, loads could follow the current conditions and make short term forecasts. Loads could adjust their consumption in response to actual or expected real time prices without actions being taken by the system operator. If the metering for real-time load is in place and consumption is settled at real-time spot prices, demand could respond to real time prices without receiving dispatch instructions from the ISO.

Furthermore, a large energy demand response is not a requirement to avoid the binary price outcomes under perverse examples with prices bouncing from low operating costs to the high average VOLL. Such outcomes require that there be no price response in the total demand for energy *and* the demand for reserves. However, as illustrated in Figure 5, even if there were no flexible energy demand response there would by construction be a price response associated with the demand for operating reserves. Of course, energy demand response would be valuable. For any level of capacity that provides a given level of reliability, there is some set of shortage prices that would produce generator revenue streams that if correctly anticipated would be sufficient to sustain that level of capacity.[20] If there is a potential for error in setting these shortage prices or for error by suppliers in translating these shortage prices into expected income, then the amount of energy demand response is a cushion against load shedding arising from errors in estimating future prices and the profitable level of capacity.

There is also less potential for error if the ISO can set an operating reserve demand curve, rather than just shortage prices for reserves, so that small errors in setting shortage prices do not drive the system too far from the expected equilibrium level of prices. And it doesn't take much of a response to move away from a system where prices bounce between the lowest to the highest level towards a system where the prices, while volatile still, trace out a more "normal" response to market conditions.

Hence, while it would be difficult to implement a pure energy-only market with no energy demand response and no pricing of reserves, once operating reserves are included in the "energy-only" market design the same conditions would not apply. More energy demand response would be better, but the energy demand response cart could come after the horse of efficient "energy-only" market design applying an operating reserve demand curve and simultaneous pricing of energy and operating reserves.

Reliability

An energy-only market design defines and prices reliability through the demand for operating reserves. It would be possible to estimate the resulting loss of load probability to compare with the traditional planning standard of one day in ten years for a loss of load event. But the expected loss of load probability would be an output of the market choices more than an input to system design. If the operating reserve demand curve properly reflected the value of reserves, the "correct" loss-of-load probability would follow automatically.

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[20] Steven Stoft, Power System Economics, IEEE Press, 2002, pp. 167-168.

In a market context, the concept of reliability differs for the two types of demand. In the case of inflexible demand, any interruption of service would be involuntary. This would conform closely to the traditional situation where the planning criterion assumed a given and fixed load and the probability that adequate generation would be available could be calculated. However, for flexible price-responsive demand the same concepts would not apply. As the market tightens and prices rise, flexible demand reduces and this by definition would not be an involuntary loss of load. Reliability becomes reliability at a price for the flexible demand.

Different levels of installed capacity would imply different prices and a distribution of probabilities for any involuntary loss of load. This would be true in both an energy-only market and in a price-capped market.[21] Given the demand curve for operating reserves, the expected long-run equilibrium loss of load probability could be more or less than any given planning standard. To the extent that there is a difference, it might be argued that the demand for operating reserves should be adjusted to match the planning standard.

However, an alternative interpretation would be that the operating reserve demand curve provides the better representation of the appropriate level of reliability. The direct consideration of the value of operating reserves captures the tradeoff that could be included only indirectly in the traditional planning standard. For example, suppose the equilibrium loss of load probability that would result from a given operating reserve demand curve would be higher than the under the traditional standard at the target level of installed capacity. This might be argued to require an increase in the demand for operating reserves in order to increase reliability. In effect, this argument would say that the price of reserves should be higher than the tradeoff defined by the operating reserve demand curve. But this argument would contradict the definition of the demand curve. If the operating reserve demand curve captures the value of reliability, the resulting expected equilibrium loss of load probability should be the standard.

This stands in contrast to an alternative approach that would fix the installed capacity requirement and determine the operating reserve demand to produce enough revenue to support investment that would meet the installed capacity target. In an energy only market, or in a price capped market, it would always be possible to set the operating reserve requirement at a level that met the expected revenue requirement and eliminated the missing money problem for a given level of installed capacity.[22]

The indirect route of specifying the expected loss of load probability should not replace the direct determination of the willingness to pay for operating reserves. If the expected loss off load probability were less than the traditional planning standard, a

[21] For an analogous discussion in the context of the ISONE LICAP design, see Steven Stoft, Testimony on Behalf of ISO New England on Locational Installed Capacity Market Proposal, Submitted to Federal Energy Regulatory Commission, Docket Number ER03-563-030, Rebuttal February 10, 2005, pp. 35-36..

[22] The energy-only operating reserve demand curve is not derived from a revenue target. The combination of energy demand and reserve demand reflects the value of the energy and reserves. This is distinct from the illustrative dichotomy between VOLL pricing and operating reserve (OpRes) pricing described in Steven Stoft, Power System Economics, IEEE Press, 2002, pp. 108-200.

similar argument would give deference to the operating reserve demand curve. Hence, while an estimate of the distribution of loss of load probabilities might inform the design of the operating reserve demand curve in judging the adequacy of reserves, by forcing questions about the realism of the operating reserve demand curve, any conflict between the two would ultimately be resolved in favor of the operating reserve demand curve. Once the willingness to pay for operating reserves is made explicit and accepted by the regulators and system operator, there would be no need to further reconcile the expected loss of load probability with the operating curve demand curve.

Other things being equal, use of the energy-only market design should reduce the cost of meeting the reliability requirements. The flexible demand provides an important added tool to meet reliability standards. The demand response should be more than found in traditional utility systems or that could be provided in price-capped markets. Without the incentive of spot market prices that reflect the real scarcity conditions, it is more difficult to design market mechanisms that provide a flexible demand response. Hence, for any given cost level the energy-only market design should produce greater reliability in terms of reduced curtailments of inflexible demand.

A similar conclusion applies to a concern that an energy only market and the associated operating reserve demand curve would produce higher average costs that somehow might be avoided. The same issue arises under ICAP systems where the capacity payments appear to raise costs to customers. However, if reliability is to be maintained, some of these costs cannot be avoided. The traditional system included these costs in the rate base for the portfolio of generation owned by the utility. The costs were there, but they were less visible than explicit capacity payments or market-clearing energy prices. The costs would not be created by the ICAP requirements or operating reserve demand curve. It is the reliability requirement that gives rise to the costs. An ICAP requirement or an energy-only market would be different means to provide the payments and achieve the reliability objective.

Implementation of a demand curve for operating reserves would require attention to adapting the standards and information from the traditional model under the NERC rules. "Grid reliability is a difficult issue to discuss objectively, because few metrics describe and measure bulk system reliability consistently across the nation."[23] While this would be important, there is nothing in principle that should deter use of an energy-only market design. The market should reinforce reliability. The reliability rules and definitions may have different impacts in a market context, but the goals of reliability are not add odds with the market design.

The NERC standards already follow a structure that includes minimum operating reserve levels that should not be breached and where controlled but involuntary load curtailments should be imposed. At the minimum levels, reserves would be purchased at any price up to the price cap. However, when the price cap is below the average VOLL, this creates a conflict that produces the missing incentives and the missing money. In the

[23] Phillip G. Harris, "Relationship between Competitive Power Markets and Grid Reliability: The PJM RTO Experience," Issue Papers on Reliability and Competition, US Department of Energy and Natural Resources Canada, August 2005, pp. 4. (www.energetics.com/meetings/reliability/papers.html)

energy-only market design, a similar rule could apply regarding the minimum operating reserve levels, but the maximum price for reserves becomes the average VOLL because generation that costs more is more expensive that involuntary load reduction.

Above the minimum operating reserve levels, there is still a value for incremental reserves but the value decreases at higher levels of reserves. Explicit pricing of these incremental levels would be part of the design to eliminate the missing incentives and missing money. The operating reserve values would be set by regulators and the system operator to capture expected impacts on the system. This should include the total change in system costs across the integrated grid if everyone followed the same principles.

Although the structure of the reserve requirements might be compatible with the existing NERC standards, the level of operating reserve requirements and associated prices might turn out to be different. The NERC standards were designed for a different setting, where the value of reliability was less explicit than would be the case with a realistic operating reserve demand curve. Explicit consideration of the tradeoffs would be required for the energy-only market design, and might change the approach that NERC takes in the new era of mandatory reliability standards. With the energy-only market design, NERC's enforcement problems would be reduced because the market incentives would be compatible with the reliability requirement.

Missing Markets

The missing money problem created by limiting scarcity pricing provides an example of a missing market. There could be a market for reliability, but the regulatory constraint prevents its operation. The implicit price caps on energy and reserves present the most significant problem of this type. As a practical matter, introducing an energy-only market design with explicit energy and operating reserve demand curves may be all that is really needed to provide adequate incentives for investment in generation and other resources.

However, there are other ancillary services that are essential for successful operation of energy systems. Black start capability, regulation services, and voltage support through reactive power management are prominent examples. These services are necessary and must at least be procured by the system operator. The compensation rules for providers of these services must be adequate. However, the total expenditure may be modest relative to the energy and operating reserves under the energy-only market design.

These other ancillary services may be amenable to targeted compensation schemes that do not much affect the remainder of the energy market design. To the extent that this is not true, then it would be important to extend the analysis of the energy-only market design to include efficient pricing and incentives for these additional services. For instance, it would be possible to consider spot-pricing and forward contracting for reactive support.

Market Power

A primary concern that drove the public policy decisions towards administrative measures like price caps was the possibility of market participants possessing and exercising market power. The immediate effect of market power was cast as high prices that could not be justified by input costs. It seemed logical that the most direct route to controlling high prices would be by imposing limits on prices. This in turn created an array of other measures such as out-of-market purchases and reliability must run (RMR) contracts. And the low prices created the missing-money problem with the attendant call for resource adequacy programs.

The concern with market power would remain in an energy-only market. With no limit on energy and operating reserve prices other than the average VOLL, there would be even greater fear about potential incentives to exercise market power. The exercise of market power would violate the assumption of competitive behavior that underpins the efficiency of energy-only pricing.

The ability of generators to enter the market with new capacity supported by voluntary contracts with consumers should make the long-term energy market workably competitive. Without artificial barriers to entry, no special policy would be required to address market power in forward contracting with a sufficiently long horizon that allows for entry.

The problem would then be in the short-term spot market, especially in the presence of transmission congestion that created load pockets where generators might have substantial market power and would be able to raise prices above competitive levels. This is a large topic with many details, but the essence of the relevant points for the energy-only market design is straightforward. The market design could include administrative intervention when and where there was a serious possibility of an exercise of (local) market power through physical or economic withholding. However, the interventions would be structured to emulate the results of competition to the greatest degree possible. These interventions would be in the form of offer caps and offer requirements for generators, with appropriate exemptions for all generators who are not in a position to exercise market power or who enter a market with new facilities.

Deciding on the level of the appropriate offer caps would be contentious, but the focus would be on preventing withholding and not on keeping prices low. With the full capacity of a mitigated plant in use, the market-clearing price would be determined by the opportunity costs reflected in the demand curves and seldom by the offer cap *per se*. Setting offer caps is even more contentious in a price capped market where the effect may be to reduce supply. Furthermore, the energy-only design does not necessarily increase any incentive to exercise market power. For the same demand response, a higher price increases the incentive to produce above any given level of output. Under these conditions, when the supplier hits its capacity constraint there is no incentive to exercise market power. To the extent that the energy-only market design increases the total energy and operating reserve demand response, the design would help mitigate market power.[24]

These types of market power interventions are familiar in the organized markets under ISOs/RTOs. The principal difference with the energy-only market design would not be in the form of the market power intervention. Rather, it would be in the treatment

[24] The common assertion that scarcity conditions increase market power depends more on an assumed movement to a nearly vertical residual demand curve than on the absolute level of price.

of scarcity pricing after mitigation to address market power. In particular, the operating reserve demand curve would allow for scarcity prices that could be very high, but would not arise from the exercise of market power. Even with offer caps in place, high demand and limited available generation capacity would create a shortage of reserves and higher prices for both energy and reserves. Hence, there would be no formal cap on prices, only limitations on economic and physical withholding for generators with market power. Market power mitigation would be targeted at the exercise of market power, not at high prices. Prices would be high during scarcity conditions and there would be no missing money.

Inadequate Contracting

If there were an adequate level of forward contracting, the contracts would reflect the expected prices going forward but customers would face relatively little exposure to the volatility of prices in spot markets. If regulators were confident voluntary contracting would suffice, the energy-only market with its voluntary forward contracts would suffice.

A principal concern of regulators could be that left to their own devices market participants might not select an appropriate level of contracting. In effect, this would be a consequence of a violation of the assumption of low transaction costs. There could be barriers to entry into contracting, particularly for small customers. Without sufficient hedges supplied through forward contracts the loads would be too exposed to volatile spot prices and this, in turn, would create inevitable pressures for regulators to intervene when scarcity appeared. This intervention would be a political challenge for regulators and would create associated regulatory uncertainty that would undermine investment.

To the extent that forward contracts would be needed by generators to maintain existing facilities or arrange the financing for new investment, insufficient demand for forward contracts could work against the intended incentives for market based resource investments. Hence, inadequate demand for forward contracts could translate into a resource adequacy problem relative to the level of investment that would occur if the transaction costs could be eliminated.

A concern with inadequate forward contracting might arise from an expectation of market failure with many small customers who are unable or unwilling to enter into forward contracts. The group illustrated above in Figure 3 as the inflexible load might have little incentive to contract. The price to the inflexible load might be fixed and probability of curtailment ignored. The load serving entities providing the inflexible load's power at fixed prices may have some incentive to contract forward, but this would depend on the regulatory design at the retail level even though the effects would be felt in the wholesale market.

Without elaborating every case, there are instances when regulators would be inclined to require forward contracting on behalf of some or all customers. In the markets where there is a missing money problem, this contracting directive moves almost immediately to contracting for installed capacity in the ICAP mode. However, in an energy-only market without a missing money problem there would be other ways to approach mandatory contracting. If the problem is forward contracting and not missing money, then the regulatory approach to forward contracting could focus on the objective and be less prescriptive about the means to achieve the objective.

Mandatory Load Hedge Contracting

The main targets for regulatory intervention would be the problems of market power and inadequate contracting. If market power could be contained with sufficient mitigation in the spot market, there would be no concern with the possibility of withholding, and the incentives of the energy-only market would provide a powerful force to make plant available when most needed. This need for mitigation is not unique to the energy-only design, and well-designed mitigation should address the market power problem.

If somehow adequate contracting could be arranged, then there would be protection for loads that would be hedged against high prices and suppliers that would avoid exposure to volatility. The challenge arises in specifying the requirement for and design of forward hedging contracts.

An “energy-only” market design could accommodate a mandatory load hedge (MLH) requirement. This would be a regulatory intervention to address the concern that there would be inadequate forward contracting. The details of MLH requirements would be important, but the critical issues introduced by an energy-only market approach would be relatively limited. The comparison with an ICAP design helps identify why removing the missing money problem would simplify the policy intervention.

ICAP and MLH

An ICAP requirement includes forward contracts with specific generators for installed capacity, sometimes with an explicit or implicit option on the energy that could be produced from the designated plant. Among the concerns with ICAP programs have been that the forward requirement horizons are not long enough to support investment, and not specific enough to support the right investments. This produces pressure to extend the horizons and specificity as to type and location.[25] Similar challenges would face any forward contracting requirement, but if the objective of MLH is framed relative to the energy-only market design, there would be important differences with the ICAP approach.

For both ICAP and MLH approaches, an initial step in specifying the requirement would be to identify the targeted load and the intended duration of the forward contracts. For the intended forward contracts, the procedure would determine the forecast load level, locations, and horizon. Although this would not be an easy task, assume that the profile of loads has been identified for each location. Under an ICAP program, this is the beginning of the process. To move load levels at specific locations to installed capacity at other locations, the load forecast must be converted into a description of the mix of transmission and generation capacity that would be required in order to meet this load requirement. The ICAP program may include specifications for demand-side alternatives with their own locational and operating characteristics. For a forecast many years ahead, this translation from demand to supply would be a complicated process with many uncertainties.

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[25] John Chandley, “ICAP Reform Proposals in New England and PJM,” LECG, Report to the California ISO, September 2005.

Under an MLH approach, however, the load forecast could be enough. There would not be a requirement to convert the forecast into a prescription for production capacity by location. The system operator might be in the best position to describe correlated generator outage risk, transmission outages, weather volatility that would determine expected prices in the energy-only market. These studies could support analysis by investors deciding on where and how much generating or other capacity to build given the resulting expectation of prices. But the assumption of the energy-only market design would be to rely on the investment decisions by the market participants even when these may differ from the choices of the regulators or system operators.

For simplicity in making the distinction with ICAP, assume the regulator requires customers to arrange for energy forward contracts that met the same forecast load used to drive an ICAP requirement. The MLH contracts could be arranged through either direct negotiations or through a formal auction process. The critical distinction relative to the ICAP approach is that these MLH forward contracts would be based on prices and delivery at the load location. In effect, these would be equivalent to financial "contracts for differences" relative to the real-time locational price at the load point. To support these contracts the supplier could arrange bilateral contracts to deliver the energy to the load at the load location, or the supplier would settle for imbalances at the locational price.[26]

Unlike with the ICAP programs, under the MLH there would be no need for the regulator or the load serving entity operating on behalf of the customer to arrange for transmission delivery or link the contract to any particular generating facility. These decisions would all be handled by the market participants who agree to be the suppliers under the contracts. The costs and risks of providing the MLH hedges would fall on the supplier and be reflected in the forward contract price. However, competition among

[26] Proposals to use financial contracts in resource adequacy programs are not new. For example, see Harry Singh, "Call Options for Energy: A Market Based Alternative to ICAP and Energy Price Caps," PG&E National Energy Group, October 16, 2000. However, most discussions of resource adequacy proposals employing forward contracts explicitly reject a strictly financial interpretation because the absence of efficient, energy-only pricing precludes the contracts from providing the right incentives for investment or operations. This missing-money problem dictates the need for the physical connection with specific resources that spawns the administrative complexity of ICAP programs. For these quasi-financial contract designs, see Miles Bidwell, "Reliability Options," Electricity Journal, Vol. 18, Issue 5, June 2005, pp. 11-25. Hung-Po Chao and Robert Wilson, "Resource Adequacy and Market Power Mitigation via Option Contracts," Electric Power Research Institute, Draft, March 18, 2004. Shmuel Oren, "Capacity Payments and Supply Adequacy in Competitive Markets," VII Symposium of Specialists in Electric Operational Systems Planning," Basil, May 2000. Shmuel Oren, "Ensuring Generation Adequacy in Competitive Electricity Markets," University of California at Berkeley, April 2004. Shmuel Oren, "Capacity Mechanisms for Generation Adequacy Insurance," CPUC-CEOB-CAISO Installed Capacity Conference, San Francisco, California, October 4-5, 2004. Roy J. Shanker, "Comments on Standard Market Design: Resource Adequacy Requirement," Federal Energy Regulatory Commission, Docket RM01-12-000, January 10, 2003. Carlos Vázquez, Michel Rivier, and Ignacio J. Pérez-Arriaga, "A Market Approach to Long-Term Security of Supply," IEEE Transactions on Power Systems, Vol. 17, No. 2, May 2002. Carlos Vázquez, Carlos Battle, Michel Rivier, and Ignacio J. Pérez-Arriaga, "Security of Supply in the Dutch Electricity Market: the Tole of Reliability Options," Report IIT-03-084IC, Comillas, Universidad Pontifica, Madrid, Draft Version 3.0, Madrid, December 15, 2003.

suppliers should drive innovation and efficiency to make the aggregate forward arrangements capture the expected benefits of the market.

Furthermore, compliance tracking under the MLH contracts would follow automatically in the energy-only market settlements of imbalances. There would be no need for the system operator or anyone else to monitor the generators or ensure the availability or deliverability of any particular generator's capacity. The market itself would provide strong incentives for the suppliers to make these arrangements in an efficient and least cost manner.

The myriad forecasting and monitoring requirements of the ICAP approach, which tend to recreate the problems of integrated resource planning, would be replaced by financial MLH contracts defined at the customer's location. A focus on financial contracts emphasizes the need for enforcement of the financial obligations. The enforcement provisions would be addressed by credit requirements that for the most part would also be present in ICAP markets. In this regard, the complexity of "physical" contracts in ICAP markets does not remove the need for enforcement of financial obligations. The typical ICAP design includes penalties for performance failure, and in the end the ICAP approach carries with it much of the baggage of the financial contract without the simplicity.

In the absence of transparent scarcity pricing of the type found in an energy-only market, a major problem for ICAP markets is to ensure compliance during periods of stress, and to make sure the requirement is broad enough and enforceable so that there is no leaning on the system. If generators could turn to a capped energy price during periods of stress, there would be strong incentives to withdraw from the ICAP obligations and pay the low damages at the capped price. Furthermore, parties outside the formal program would attempt to purchase from the capped spot market during periods of stress. It is a major challenge in ICAP markets to devise sufficient penalties, export controls, delivery obligations and enforcement mechanisms to ensure that the intended generation capacity, transmission deliverability or demand response is really available during periods of aggregate scarcity when real opportunity costs exceed the price cap. By contrast, the MLH requirement could be targeted to a part of the load, and regulators would not be faced with the problem of dealing with market participants outside their jurisdiction or outside the intended target of the program. In other words, the MLH requirement could focus in particular customer classes (e.g., residential and not industrial) and regions (e.g., inside the state and subject to state regulation).

The gold standard for ICAP programs is a set of penalties and enforcement rules that attempt to emulate the incentives of the energy-only market.[27] Of course, by construction the energy-only market creates these incentives naturally as part of its inherent design. There would be no need to have special monitoring and enforcement for generators during periods of scarcity because in the energy-only market this is precisely

[27] For example, the LICAP proposal of ISONE attempted to emulate as much as possible the incentives of an energy-only market through the design of monitoring and performance incentives. Steven Stoft, Testimony on Behalf of ISO New England on Locational Installed Capacity Market Proposal, Submitted to Federal Energy Regulatory Commission, Docket Number ER03-563-030, Direct August 31, 2004, Supplemental November 4, 2004, Rebuttal February 10, 2005.

when (very) high prices provide (very) strong incentives to perform. There would be no need for export limitations because the export loads not covered by the MLH obligation would be paying the real opportunity cost of their demand. Likewise there would be no concern with loads not covered by the MLH requirement leaning on the system because there would be no where to lean, only to stand straight and pay the full opportunity cost in the energy-only market when scarcity conditions arose. The MLH approach would provide the hedges through contracts that apply only to the parties that have contracted.

This structure would be consistent with retail access systems like the Basic Generation Service (BGS) in New Jersey.[28] The BGS involves an auction for forward procurement of energy delivered to the load. There is no specification in the contracts about how or where the supplier obtains the power or hedges its obligations. This is left to the supplier's activities in the market and the supplier's risks are internalized in the offers it makes in the auction. The rolling horizon is three years for the smallest customers and one year for larger commercial customers, with the alternative to opt out of the protection. The largest commercial and industrial customers are not included except for uplift and ICAP payments. In the context of an energy-only market design, where there would be no ICAP payments, it would be natural to ask if anything in addition to the BGS program would be required.

This outline of the relative simplicity of an MLH approach in an energy-only framework follows from its targeting of protections. In a price-capped energy market, the capped prices apply in theory to all spot transactions. In order to achieve the benefits of the forward ICAP contracts and associated investment, regulators would face the broad choice between either contracting enough so that spot prices naturally stay below the price cap for the free riders or restricting access to the capped prices through exclusionary rules that would apply during periods of scarcity. The free riders would create very high costs for those bearing the burden of forward contracting. The exclusionary rules would exacerbate the complexity and incentive problems that undermine the very purposes of the market.

By contrast, the energy-only market would not provide hedges through capped spot prices that would apply to everyone. Hence, forward contracting requirements could be limited to a targeted group. There would not be the great concern with free riders. Reaping the benefits of the forward contracts would not require exclusionary rules.

The focus on financial contracts provides great flexibility for suppliers to craft generation, transmission and demand efficiency packages to support their commitments under the MLH contract. There need be no rules to overcome missing incentives or decide on the tradeoffs between supply and demand alternatives.

In short, an MLH requirement would be an intervention by regulators to address a concern that, despite the strong incentives of the energy-only market, loads would not have sufficient interest or incentive to arrange the long-term hedges that would eventually prove necessary. But the intervention would be tailored to fit the intention of using

[28] For a description of the New Jersey forward contracting requirement, see http://www.bpu.state.nj.us/home/bgs.shtml

market pricing to drive investment decisions. The required contracts would be financial instruments without explicit connection to any particular resources.

MLH and Other Contracts

Energy-only market pricing would be essential in relying on these relatively simple MLH instruments. Absent credible scarcity pricing of the energy-only market, any MLH requirement would confront the same perverse conditions that would compromise incentives and generator performance precisely when needed the most, during times of scarcity. An energy-only market approach could come as part of a package, with some form of MLH contracts to provide the needed hedges and the forward contracts underpinning investment in new generation (and transmission) capacity.

The generic outline of an MLH approach leaves open many details about the particulars of contract design. The essential features would be an (i) energy-only market design, (ii) specification of the obligation in financial rather than physical terms, and (iii) linking the financial terms to the prices at the load location. Within this framework there could be a variety of contract requirements that would satisfy the limited objectives of hedging sufficiently to provide the protection sought by regulators and to support the intended investment. The MLH approach would not face the additional demands of assuring operational performance or mitigating market power. These would be handled by the incentives and mitigation rules in the spot market, respectively.

The MLH form of financial contract would have much in common with the familiar “portfolio” contracts with liquidated damages (LD) found in electricity markets. The LD contracts do not identify particular resources, and the obligation is to deliver the energy from somewhere or pay the liquidated damages. The damages are often determined as the spot-market prices. In the context of a spot market, the LD contracts are financial instruments, and in a price-capped market the damages are capped. Hence, a principal complication under the price-capped energy markets is that the liquidated damages are too low, and the supplier has an incentive to lean on the spot market and pay the capped spot price during times of scarcity. As a result, the price hedging value of the LD contract remains for the customer but the contract does nothing to eliminate the missing money or the risk of involuntary curtailment. With only the obligation to deliver the energy or pay the low penalty, the equilibrium price for LD contracts would not substitute for the missing money in payments to generators. The money would still be missing from the price-capped energy market and would not be provided through the LD contract. In a price-capped market, LD contracts would be part of the problem.

By contrast, under the energy-only market approach these LD contracts might well be compatible and workable hedging instruments to substitute for some or all of the MLH requirements. To the extent that the LD requirement specifies the payment obligation as it appears in the market, movement to an energy-only market would increase the *de facto* penalty payments in the LD contracts. If these payments were also keyed to the locational price of the load, then the LD contracts could be fully included in meeting the MLH requirement. In an energy-only market, LD contracts could be part of the solution.

Under the energy-only framework, the function of the MLH requirement is more limited and the scope of the contracts more flexible than for the capacity contracts in a comparable ICAP design. Under the energy-only market design, there is no missing money and forward contracts would not carry the burden of providing additional payments above the forward price of energy. Under the energy-only market design the focus of market power mitigation would be on the spot market and not be imposed as a design constraint for the forward contracts. Under the energy-only market design spot prices would provide the incentives for generator availability during periods of scarcity and would not require performance features on the contracts.

The test of the adequacy of the MLH requirement would be in the regulator's judgment that the contracts provided sufficient hedging on average and were of long enough duration to support investment in generation and other resources. For example, it might suffice to specify the MLH requirement in terms of peak and off-peak energy blocks that follow the common pattern of bilateral arrangements. The total energy over the month for peak periods would be set, with a separate requirement for off-peak periods. The load would have the discretion as to when to exercise the contract within the period. Suppliers might contract to provide the hedge for some or all the energy and for some or all the period. This flexibility would avoid the need to specify in advance exactly which hours would apply for availability of particular quantities, avoiding some of the complications of the ICAP programs.

In addition, regulators may wish to leave some customers with a certain amount of discretion while ensuring that there is a minimal level of hedging. Hence, the MLH requirement might be specified as a call option at a high price for the contracted energy over the period. Hedging contracts with lower strike prices would suffice to meet the requirement. Further, the MLH specification could have different requirements for different groups. For example, commercial customers might be required to arrange at least the call options at a high price, while regulators might require smaller residential customers to have full requirements energy contracts at a fixed price. The challenge would be to devise a set of acceptable MLH requirements that did not require extensive review in substituting alternative contracts to meet the requirement.

The New Jersey BGS system employs flexibility in both duration and application to different customer groups. The rolling horizon for the residential load means that one-third of the forecast load is contracted anew three years in advance. Large customers have no forward obligation and can seek their own hedging arrangements or rely in part or all on the spot market.

An alternative type of flexibility might be to formulate the MLH contracts as synthetic tolling arrangements. In effect, the contract would set a price for delivery of electric energy to the load and a price for delivery of a mix of input fuels to the supplier at a standardized location. This would provide the load with a long term hedge for the non-fuel costs ("capacity") but exclude the hedge for fuel costs. This would allow for a separate decision by the load to hedge the fuel costs, perhaps closer to the time of delivery. The suppliers would avoid taking on the complete long-term fuel price risk. This might be a more attractive allocation of risk for both parties.

Since the economic incentives for investment and for operations flow from the energy-only market design and transparent scarcity pricing, the direct purpose of MLH contracts would be hedging and need not address the operations problems under the ICAP approach. There would be few limits on the flexibility of MLH requirements. The details would address the matters of duration, amount, strike price, credit requirements, and substitution rules. But as long as the requirements were specified as financial contracts relative to the load location and real-time price, the contracts would be largely independent of the remainder of the market design and operation. The contracts would impose minimal requirements on the system operator.

Transition

The sketch of an "energy-only" market design sets a destination but does not define the path. It is common in discussions of ICAP proposals to accept this destination as a goal but not consider how to get there, partly because the goal is not adequately defined. With a common understanding of the objective, it would be easier to make choices along the way.

The transition would be important and it would depend in part on the starting point. If there is no existing ICAP program and no imminent capacity shortage, the focus would be on implementing the critical reforms of the spot market design to include transparent scarcity pricing. Similarly, if there is no load hedging program in place, then this would be a focus of a regulatory decision to either accept reliance on voluntary forward contracting as politically sustainable or turn attention to mandatory load hedging for some of the customer classes.

In regions with ICAP reforms underway, and real fears of immediate capacity shortages, the attractions of an energy-only market may require a period of confidence building. However, there appears to be nothing that dictates that an improved spot market design is mutually exclusive of an ICAP approach. The absence of transparent scarcity pricing makes an ICAP program necessary and more difficult to implement. But transparent scarcity pricing for energy and operating reserves would simplify many of the monitoring and performance problems that come with an ICAP approach.

A goal of moving to an energy only market design should influence the design of any ICAP program. The better the scarcity pricing the less burden there would be on designing performance standards, the easier it would be to develop demand alternatives, and the easier it would be to set criteria for phase out of the ICAP system. For example, recent ICAP reform proposals such as the Reliability Pricing Model in PJM set the demand for installed capacity with the price determined net of an estimate of the revenues that should be earned in the spot market.[29] With transparent scarcity pricing and an appropriate operating reserve demand curve (plus a compatible installed reserve planning target and a few other simplifying assumptions) this net price of capacity would be zero and the role of the ICAP requirement would fade, or at least be substantially reduced.

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[29] John Chandley, "ICAP Reform Proposals in New England and PJM," LECG, Report to the California ISO, September 2005.

A common step would be to address directly the interaction between reliability standards and market design. The Energy Policy Act of 2005 requires FERC to propose rules to establish a new Electric Reliability Organization (ERO), set mandatory reliability standards and provide for enforcement.[30] These new standards could be compatible with the principles of the operating reserve demand curve, or not. Everyone would benefit if the standards and rules were written in explicit recognition of the charge to have markets reinforce reliability.[31] Poorly designed markets and poorly designed reliability standards would make everything harder.

An explicit consideration of the destination and the transition path would be important for mitigating regulatory risk. Market observers regularly identify uncertainty about regulatory rules and pricing as a principal obstacle to investment. Hence, despite any promises that the rules will be stable, an unsustainable system will be seen for what it is and the confidence required to support investment will be impossible to mandate. The basic elements of a successful market design are not a mystery, and experience shows that deferring attention to market design increases the likelihood and cost of the failures, requiring ever more interventions and changes of the rules. It is reasonable to conclude that moving quickly to a successful market design is a necessary condition for mitigating regulatory risk.

Conclusion

The missing money problem reflects a view that market design imperfections suppress electricity prices in spot markets. This produces inadequate incentives to invest in infrastructure resources such as generation capacity and its substitutes. A common policy response is to mandate purchases of installed capacity as a resource adequacy requirement. When this proves inadequate, more prescriptive reforms arise to compensate for the missing incentives in the market. An alternative approach would be to address the imperfections in the market design, provide the missing incentives, and eliminate the missing money. The resulting "energy only" market would not remove the need for regulatory interventions, but it would substantially change the character of those interventions. A sketch of such a market design illustrates how to address the market imperfections without overturning the market.

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[30] Federal Energy Regulatory Commission, "Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards," 18 CFR Part 38, Docket No. RM05-30-000, September 1, 2005.

[31] U.S.-Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," April 2004, p. 140.

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Endnotes

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ATTACHMENT 4

Discussion Paper on Resource Adequacy for the Midwest ISO Energy Markets

I. Introduction and Overview

The terms "resource adequacy" or, equivalently, "supply adequacy" relate to the concept of whether or not there has been sufficient investment over time in physical assets (including generation, transmission, distribution, and demand-side measures) to ensure that the supply and demand for electricity in real time can be balanced at some price. By this definition, resource adequacy is a long-term, or investment, issue. That is, resource adequacy is not, nor should it be, *primarily* related to (1) flaws in spot market design (including Day Ahead and Real Time Energy Markets) that may cause participants to periodically or systematically withhold capacity, or (2) the "management" of price volatility.

Resource adequacy is important for at least two reasons that are fundamental to the future of the industry. First, the financial consequences are significant. It is understood that physical investment in the electricity industry is both needed and costly. What is less well known is that the difference between the cost of investment facilitated (i.e., incentivized) under different institutional structures could potentially be very significant. It is not an oversimplification to say that cost alone justifies the amount of debate that has occurred. Second, to date the primary focus of ISOs/RTOs has been on designing, implementing, and operating short-term electricity markets (i.e., Day Ahead and Real Time Energy Markets).[1] The dominant organizing principle behind these markets has been the implementation/operation of centralized bid-based dispatch to achieve reliability and efficiency gains in how the existing infrastructure is used. The design principle underlying these markets is that as long as reliability is maintained, the dispatch function itself should remain indifferent to any specific outcome. That is, the ISOs/RTOs are not *principals **in** the market* but rather *service providers **to** the market*.

Long-term markets such as those for capacity and financial transmission rights are therefore problematic because they potentially make an ISO/RTO a principal. The reason being, is that in the absence of a proper market, i.e., one with both buyers (demand) and sellers (supply), the RTO has to serve as one side of the market. In the case of capacity, certain proposals currently under discussion establish the ISO/RTO as the single buyer acting on behalf of future demand in determining a price. In other words, the ISO/RTO is both a service provider and a principal. The creation of this new relationship raises

[1] The obvious exception to this assertion is the market for Financial Transmission Rights, which extends out a year. It is also worth noting that the NYISO originally offered FTRs with a 5-year time horizon but has been gradually reducing the length of these instruments.

important questions around market design,[2] regulatory matters,[3] and commercial obligations.[4] Creating a forward looking capacity construct is therefore potentially not "just" an incremental increase in responsibilities for an ISO or RTO; but rather it is a significant structural change to the role they currently perform.[5]

Given that resource/supply adequacy is (or should be) focused on investment in physical assets[6] the central question is: what mechanisms guide or facilitate investment decisions? In a market arrangement it is, among other things, the forward price. If there is no market – or if the market is "poor" – alternative mechanisms have to be used. It is useful then to begin the discussion on a potential capacity mechanism for the Midwest ISO Region with the question of how best do we enhance and/or create a forward price signal that will guide or facilitate investment decisions.

II. Regulatory Imperatives

The Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") received directives from the Federal Energy Regulatory Commission ("FERC" or "Commission") to file with the Commission a "permanent" or long-term plan that will address resource adequacy requirements in the Midwest ISO Region no later than June 1, 2006.[7] In developing this plan, the Commission has provided that the Midwest ISO should:

- Consider: (1) the unique characteristics of the Midwest ISO's Market Participants; (2) the Midwest ISO Region's needs; and (3) the views of applicable state regulators and the Organization of MISO States ("OMS");

- Give due consideration to stakeholder views, although FERC recognizes that achieving uniform agreement on all aspects of such a plan may be impossible;

[2] For example, how does the "market" ensure that the least-cost dispatch objective is pursued regardless of capacity decisions that have been made by the ISO/RTO?

[3] ISOs/RTOs while having State Regulatory Authorities as their stakeholders are regulated by the Federal Energy Regulatory Committee.

[4] To the extent that ISOs/RTOs engage in activities that are very similar to Integrated Resource Planning, are local utilities absolved from performing similar exercises? If not, how are conflicts between the two (or more) plans resolved?

[5] While ISOs/RTOs engage in transmission planning they do this as a service to their customers and they do not establish a price or enter into contracts – either implicit or explicit – that affect planning outcomes.

[6] Where there term is understood to include any processes or procedures related to demand-side management.

[7] *Midwest Independent Transmission System Operator, Inc., et al.*, 108 FERC ¶ 61,163 at P 397 (2004) ("August 6 Order"), *order on reh'g*, 109 FERC ¶ 61,157 (2004) ("November 8 Rehearing Order"), *order on reh'g*, 111 FERC ¶ 61,043 (2005) ("April 15 Rehearing Order").

- Provide a consistent platform to support the region's short-term reliability needs and encourage long-term planning and investment in infrastructure;
- Develop a construct that does not directly conflict with the resource adequacy requirements of the PJM Interconnection ("PJM").

III. Jurisdictional Issues

In FERC's August 6 Order on the Midwest ISO's EMT, it stated that "we expect that the final RAR plan will give due consideration to stakeholder views…".[8] These stakeholder views include the views of the OMS. While stakeholder views are disparate, certain State Regulators firmly believe that the states have sole jurisdiction over the resource adequacy construct. In furtherance of this position, many parties cite the Federal Power Act, where it states, "The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over 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, or over facilities for the transmission of electric energy consumed wholly by the transmitter."[9]

The diversity in the Midwest ISO Region results in market participants in certain states in the Region being vertically integrated utilities where the state regulatory commission works with these companies to set adequate reserve margins using some form of an integrated resource planning process ("IRP"). Still, other market participants in certain other states in the Midwest ISO Region have state regulatory commissions that have voluntarily chosen to defer setting reserve margins to a regional body like the regional reliability organization ("RRO"). In either case, it's not clear if the state regulatory body has a desire to relinquish this kind of influence on the setting of reserve margins for their regulated utilities.

Recognizing the dichotomy between Federal and State Regulatory preference related to Resource Supply Adequacy, the Midwest ISO will endeavor to implement a construct satisfies federal regulatory directives while recognizing the diversity of state regulatory oversight in this area.

IV. Current MISO Market Design

Several aspects of the energy markets articulated in the Midwest ISO's Transmission and Energy Market Tariff ("EMT") are relevant to a discussion

[8] See ¶ 397 of August 6 Order.
[9] See § 201(b) of Federal Power Act.

on capacity markets. First, the current Tariff does not include a specific capacity market. While there is a linkage between capacity and the energy markets through Module E, the Midwest ISO does not operate a capacity construct. Second, not only is there a $1000 ceiling on offers into the real time market, there is real time dynamic market monitoring and mitigation. Third, the EMT codifies NERC reserve requirements for each of the three reliability regions in the footprint.

In essence the Midwest ISO operates a physical real time market and a financial (very near term) forward Day Ahead energy market. Module E notwithstanding, long-term generation capacity does not currently play a role in either the Midwest ISO's market operations or in the market aspects of the EMT itself (i.e., Modules C, D, and E of the Tariff). The extent to which long-term "capacity" is linked to the market is limited to the relationship between transmission service, designated network resources and eligibility in the allocation process for Financial Transmission Rights. However, it is worth noting that as a short-term concept capacity (i.e., operating as compared to planning reserves), is an important aspect of reliability.

V. Past, Present and Future Trends in Capacity Market Constructs

Capacity market constructs in the eastern ISOs/RTOs began with the Installed Capacity ("ICAP") approach, though prior to this they had reserve requirements to meet their resource adequacy needs. Under this ICAP approach, resource owners participating in the capacity market received capacity payments for some estimated maximum output from the plant. These ICAP payments were to ensure adequate supply was available to meet demand under peak load conditions. Over time it became apparent that if the ISO/RTO was going to meet its short term reliability standard, then outage rates for resources needed to be considered when buying capacity in the capacity markets. Resources were receiving capacity payments for capacity not available during the operating year. As a result, the eastern ISOs/RTOs moved to the Unforced Capacity ("UCAP") approach.[10]

The UCAP approach solved the problem of availability of the resources by calculating a historic forced outage rate for each resource and then used the rate to decrement the available capacity that the resource could offer into the capacity market. Unfortunately, this approach creates some perverse incentives like a reluctance of resources to report forced outages, endangering reliability by leaning on the system. In addition, other design elements like universal deliverability, fuel and emissions use limitations, resource mix, vertical demand curves and bipolar capacity prices became significant issues in UCAP markets:

[10] Some participants may still call it an ICAP approach, though in fact the ISO/RTO is counting only unforced capacity.

- Universal deliverability. With little or no locational deliverability requirement, capacity can be built where it is cheapest to build, without regard to enhancements in reliability, especially if capacity revenues recover a significant portion of a unit's costs;

- Use limitations. Capacity can count as meeting resource requirements, without regard to whether, for example, gas will be available for operating a CT, or emissions limits would be restrictive during critical operating hours;

- Resource mix. Capacity is required to meet a peak load forecast plus a reserve margin, ignoring the load duration curve. This means excess capacity is prevalent for huge amounts of the calendar year;

- Bipolar capacity prices (i.e., capacity prices that went from very low to very high without hitting an intermediate level). With daily capacity auctions to accommodate retail access programs, if supply is limited, capacity auction prices move towards the capacity price cap. If supply is slightly in surplus, the market-clearing price moves towards zero. These prices occur in part because the ISO/RTO has a fixed reserve margin target which translates into a vertical demand curve. Bipolar capacity prices result in increased risk for investment;

- Vertical demand curves. Imposing a downward sloping demand curve dampens the price volatility, and hopefully reflects enhance reliability with additional reserve procurement.

As a result, the eastern ISOs/RTOs have moved to towards another capacity approach. The New England ISO has developed the "LICAP" or Locational ICAP market while PJM has produced the Reliability Pricing Model or RPM. Similar in some ways, the trend in capacity market constructs appears to:

- Impose locational requirements;

- Account for forced outage rates for resources;

- Provide capacity payment premiums for resources that provide more operational flexibility, like black start or load following;

- Impose sloped demand curves set by administrative fiat.

PJM's RPM has these design characteristics in its capacity construct, as does ISO NE's LICAP. The three primary differences between the two proposals are:

- While RPM establishes capacity needs using a four year time horizon, PJM purchases on behalf of future load on a yearly basis. In contrast, LICAP is based on a one year time horizon with ISO NE running a monthly spot auction to procure the required capacity;

- Whereas RPM uses unforced capacity in the usual way, LICAP calculates capacity based on the unit's availability during 'shortage hours';

- The RPM proposal allows for resources with specific characteristics, e.g. load following, while LICAP includes no such proposal.

New England filed their proposal with FERC on March 1, 2004.[11] On June 2nd of that year, FERC delayed the effective date instituting LICAP from June 2004 to June 2006, and established hearings on critical LICAP design issues. The ALJ issued his decision on June 15 2005. PJM has yet to file their RPM proposal although they continue to have ongoing discussions with their stakeholders.

VI. Steps Forward

As stated above, the Midwest ISO must file a long-term resource adequacy plan with FERC. In developing this plan there are specific characteristics of the Midwest ISO's Region that must be accounted for in a fundamental rather than peripheral manner. Specifically:

- The electrical, political and regulatory diversity of the footprint;

- The stage of market development, (i.e., the Midwest does not have a long history of centralized market structures in electricity);

- The implementation costs, as well as, ongoing administration costs;

- The costs and benefits of the proposal as compared to the "counterfactual" (i.e., the most likely alternative).

In addition there are specific general guiding principles that should be used to guide the recommendation:

- The Resource Adequacy Plan should enhance system reliability and security;

[11] Importantly the Proposed Energy Bill specifically recognizes the LICAP proposal and requires FERC to "carefully consider the States' objections."

- The Resource Adequacy Plan should provide market participants with reliable price signals that will drive investment in generation and transmission assets;

- The Resource Adequacy Plan should not impose any additional costs for the Midwest ISO's market participants without a commensurate increase in system reliability;

- The Resource Adequacy Plan should not promote the abuse of market power;

- The Resource Adequacy Plan should not be in conflict with the market principles identified below.

Finally with respect to market design and operation the Midwest ISO has endeavored to implement robust, transparent and competitive spot energy markets to manage congestion on the electric grid. To achieve these kinds of results.

- Markets work best when there are many buyers and sellers;

- Markets work best when market participants voluntarily choose to participate in the market;

- Sellers will sell if there's an opportunity to earn a return commensurate with the risks; and

- Competition yields lower prices.

Based on the above characteristics and guidelines, the Midwest ISO believes that the appropriate starting point for discussion on a eventual capacity market is to focus on the efficacy of long-term forward contracting.

With that as the working hypothesis, the Midwest ISO believes that it can best achieve resource adequacy by promoting the use of long-term energy contracting and performing an advisory role in transmission and resource planning. Long-term energy contracting can be facilitated by developing and offering a standardized forward energy contract and by creating the incentives for market participants to engage in such contracts by letting the Midwest ISO energy markets work through a relaxation of the offer caps, an alteration of the market mitigation protocols and the offering of long-term FTRs.

<u>Energy Plus Operating Reserve Markets</u>

When functioning properly, energy markets with relaxed offer caps and altered market mitigation protocols will promote resource adequacy and create the incentive for investment in infrastructure. Spot markets primarily run to maintain system balance and reliability – they are not intended to be the primary source of revenue for asset owners, i.e., spot markets are imbalance markets and are intended to complement rather than substitute for bilateral contracts which should remain the dominant transaction medium. Resource owners will invest in new assets if there's an opportunity to earn a return on their investment commensurate with the risks. Allowing real time spot prices to reflect the supply-demand balance should allow owners of infrequently used resources the opportunity to recover a portion of the fixed costs assigned to such units in the spot markets. This opportunity, if not fleeting, will provide a clear signal for investment in infrastructure.

In coordination with the Independent Market Monitor ("IMM"), the Midwest ISO shall include relaxed offer caps and altered market mitigation in its energy markets to allow generation resource owners the opportunity to recover some of their fixed costs and create the incentive for long-term contracting.

1) Offer Caps – relaxed. A balance must be struck between the political reality of necessarily lower offer caps and appropriately higher caps for investment incentive. As a transition it might be prudent to relax the existing $1000 offer cap by $500 each successive year under the new Resource Adequacy Plan.

2) Market Mitigation – altered. Market Mitigation should not create or exacerbate a supply shortage by capping prices below the level needed to attract investment that would relieve the shortage. Conduct and impact tests can be developed that are tailored specifically based on whether resources are in rate base, have long-term contracts or depend significantly on revenues from the spot markets. Cumulative price thresholds can be developed specifically for each resource.

The Midwest ISO's Energy Markets will more accurately reflect the cost of wholesale power and provide direction for infrastructure investment. They will provide economic signals indicating where investment in the bulk power system is needed, whether it is in generation, transmission or demand side response. They will provide the correct price signals to influence market behavior while providing mechanisms to hedge against congestion costs as well as price uncertainty and volatility in the Real-Time Energy Market.

Long-term Energy Contracts

Allowing for the possibility of spot market price volatility is the key for creating incentives for long-term contracting. Forward energy contracts can serve several purposes:

- Buyers can use forward contracts to lock in prices for blocks of energy required to serve load over various terms; therefore, allowing buyers to hedge against price increases;

- Sellers can use the contracts to lock in prices for their energy production over various terms therefore allowing sellers to hedge against drops in prices;

- Traders can seek profitable arbitrage opportunities;

- Forward contracts can ensure that adequate generation capacity will be in place to meet demands in the future.

While the market participants will determine the final terms of the contract, the forward energy contract will take a standardized form with certain terms that will allow it to be a fungible instrument that may be traded many times prior to the actual delivery of the energy contracted for under the contract. Specifically, the contract will need to take into account the homogeneity of the good sold under it, the deliverability of such good, and the settlement of such good and possible liquidated damage provisions.

With a standardized contract, the parties to the contract can evaluate the risks that they face and pursue a way to mitigate those risks. For example, a party selling energy forward could control the risks it faces in meeting its obligation by investing in generation capacity or demand side options. The existence of a market for forward contracts could ensure a party investing in generation capacity a guaranteed income stream it may need to secure financing for its project.

Buyers have little incentive to engage in long-term contracts in a market with stringent market mitigation and offer caps.

While longer term contracts currently exist, they do not provide for a long-term hedge to accompany the transaction contemplated by the contract, therefore limiting transactions under such contracts. The proposed contract and accompanying long-term financial transmission rights ("FTRs") discussed in the next section will fill a gap that exists in the current industry transaction structure.

<u>Long-term FTRs</u>

The parties to a forward energy contract may be exposed to congestion costs. The hedge provided by a forward energy contract will be incomplete unless the parties to the contract can also hedge the congestion costs to which they will be exposed. A means to obtain appropriate long-term FTRs would provide an opportunity to hedge such congestion costs.

If the ISO/RTO over allocates the capacity of the transmission system when it provides FTRs (including long-term FTRs), the market participants are likely to bear the costs of the over allocation whether through pro-rated payments to FTRs or uplifts to fund the FTRs. This would tend to blunt any incentives for investment by market participants.

As a result of these two countervailing effects, the ISO/RTO should proceed slowly and incrementally in offering long-term FTRs. One approach would be to offer long-term FTR entitlements to market participants with commensurate long-term energy contracts, but only in the first tranch of the FTR allocation.

Many issues lend themselves to the discussion surrounding forward energy contracts and long-term FTRs ranging from the theoretical to the technical. The Midwest ISO identified a number of these issues in its comments on long-term FTRs submitted to the Commission on June 26, 2005. The Midwest ISO envisions a vigorous debate in the stakeholder process to iron out the details surrounding the issuance of long-term FTRs.

<u>Demand Response</u>

Buyers have little incentive to offer demand response resources in a market with stringent market mitigation and offer caps because typically, the cost of providing demand response exceeds the offer caps. Allowing for the possibility of spot market price volatility with potential for high scarcity prices is the key for creating incentives for demand response offers. Price responsive demand can set the market clearing prices in shortage conditions and trim the needle portion of the load duration curve.

<u>Reserve Requirements</u>

One of the roles of an RTO is to perform long-term planning and analysis for the region. Currently the Midwest ISO performs generation and transmission adequacy assessments. An energy-only market may require the ISO/RTO to not only perform long-term analyses but short-term as well, to ensure reliable grid operation.

1) State or RRO requirements. States and/or RROs can continue to set reserve margin requirements for market participants under their jurisdiction.

2) ISO planning. With the incorporation of a standardized forward energy contract, the Midwest ISO can look ahead to assess resource adequacy in its footprint. One tool to accomplish this task would be offering LMP price forecasts. These price forecasts can be useful information for market participants to consider investment in infrastructure. Periodically, the

Midwest ISO would update these price forecasts; for example, these forecasts could be updated one year prior to the Operating Day, six months prior, 3 months prior and the like.

Operating reserve requirements, both the nature of these requirements and the mechanism for achieving it, are appropriately being addressed by the Ancillary Services Task Force, a Midwest ISO stakeholder group.

VII. Conclusion

The Midwest ISO's proposed resource adequacy construct differs from the eastern ISOs/RTOs' existing or proposed capacity market mechanisms in the following ways:

- ***States' rights regarding the levels of resource adequacy required by state entities are maintained;***

- ***The Midwest ISO is not imposing on all market participants in its footprint a market clearing price for capacity or future energy through a capacity market construct. Forward prices can be arranged voluntarily by market participants through bilateral arrangements. As this resource adequacy construct moves towards further development, the Midwest ISO may facilitate an exchange where market participants can move from their long or short positions;***

- ***This Midwest ISO resource adequacy construct has the flexibility to encompass physical capacity mechanisms like the MAPP construct under its umbrella, depending on the needs of market participants and the requirements imposed by state jurisdictions;***

- ***The cost implications and risks associated with this resource adequacy plan are dwarfed by comparison to PJM's or ISO NE's proposed capacity market constructs.***

ATTACHMENT 5

An Energy-Only Resource Adequacy Mechanism

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Wholesale Market Oversight

Disclaimer: The ERCOT electricity market does not have a formal resource adequacy mechanism. For a number of years, a number of markets in the United States have used a capacity-and-energy mechanism to ensure reliability and encourage resource adequacy. The purpose of this paper is to present a framework for discussing a sustainable energy-only resource adequacy mechanism for ERCOT as a possible alternative to existing and proposed capacity-and-energy mechanisms. This paper is neither an endorsement of an energy-only approach nor a reflection of Staff's opinion about the shape of a resource adequacy mechanism.

Summary[1]

A successful resource adequacy mechanism provides sufficient financial incentives for the development and retention of sufficient resources to maintain reliable operation of the ERCOT grid. Over the past three years the Commission has debated versions of a capacity-and-energy resource adequacy mechanism, including the various flavors of an installed capacity (ICAP) market seen in PJM, ISO-NE, and the NYISO.[2] A capacity-and-energy mechanism would ensure that ERCOT would have sufficient resources by providing capacity payments to resources in exchange for less price volatility.[3]

What has been missing in the debate has been a detailed discussion about an energy-only approach to resource adequacy. An energy-only resource adequacy mechanism would allow (occasionally) very high prices and voluntary (market-based) load-shedding without capacity payments to resources. This white paper attempts to present the benefits and risks associated with an energy-only approach that could provide a benchmark for discussion of various short-term and long-term resource adequacy mechanisms at the Commission.

This issue is particularly timely given that the ERCOT market is at a critical juncture in market design. In addition to the decision whether to implement Texas Nodal or make changes to the current zonal market design, the Commission will debate what type of resource adequacy mechanism to implement as well as identify a market mitigation

[1] Thanks to Shmuel Oren, Parviz Adib, Richard Greffe, Keith Rogas, Jess Totten, and Sam Zhou for their input on this white paper.

[2] For a survey of existing and proposed capacity-and-energy resource adequacy mechanisms in these markets, see Staff's status report memo on the Commission's resource adequacy rulemaking filed on August 27, 2004 in Project No. 24255, *Rulemaking Concerning Planning Reserve Margin Requirements*.

[3] Capacity payments discussed here are for long-term planning reserves, which differ from capacity payments to (day-ahead) operating reserves.

mechanism that will be consistent with the chosen design and will influence further development of the ERCOT market.

This paper will discuss a number of non-market barriers that the Commission and ERCOT should address over time to create the conditions and infrastructure that will allow an energy-only resource adequacy mechanism to work, particularly with respect to greater use of demand-side resources.

The ERCOT wholesale and retail markets might benefit from a pricing regime that provides the appropriate incentives to accelerate implementation of technological advances that would provide customers with the fruits of deregulation while providing protection for risk-averse market participants. The opportunity (and risk) of higher prices during peak periods (rather than relying on capacity mechanisms) would be the catalyst for properly valuing new technologies or techniques.

An energy-only approach would provide a more market-oriented method for increasing the elasticity of demand while allowing generation, especially non-baseload capacity, to be a viable part of the ERCOT market without the need to operate a “capacity” market for planning reserves. An energy-only approach could reduce capacity costs by creating a competitive environment for the services that generation units with low capacity factors (*e.g.*, peakers) traditionally have provided to ERCOT during summer peak load. While an energy-only approach could add price risk to retailers, generators, marketers, and load in ERCOT, this approach could allow market participants to extend the success of the ERCOT market by taking advantage of technological advances to develop a long-term strategy of transforming the electricity market by increasing elasticity of supply and demand.

While an energy-only resource adequacy mechanism could provide benefits to the ERCOT market, such an approach has the following risks and trade-offs:

- Price spikes in the real-time market could be a magnitude greater in size than the market experiences today.
- Credit risks likely would increase for retailers and other load-serving entities (LSEs).
- Demand-side participation would have to be significantly greater than the ERCOT market has seen to date.

To minimize the impact of these potential drawbacks, the Commission and ERCOT would need to make a serious commitment over a period of years to get all parts of the ERCOT market and transmission system to work in harmony with an energy-only resource adequacy mechanism.

Historical Treatment of Reserve Margin

Reliability of electric service has been a priority of the Commission since its inception in 1975 and will remain a major concern for years to come. Prior to the introduction of retail competition, the Commission required utilities to maintain a target reserve margin of 15%, as ERCOT recommended. The Commission ensured that integrated utilities would serve retail load and meet prevailing reliability standards. This approach required a mix of resources, including baseload units, that served the level of load that didn't fluctuate from season to season, new capacity to plan for forecasted load growth to meet future reliability needs (as defined by the reserve margin), and units that had to be available to serve peak loads but did not need to run all year round. The Commission set the price of electric service to allow the utility a reasonable opportunity for cost recovery on its investment.[4] During most of the 1990s, utilities could build new generating facilities only if they were approved in their Integrated Resource Plans, which required utilities to review alternatives to constructing generating facilities (purchased power, demand-side management, renewable resources, etc.)

Sending timely and accurate price signals to the majority of customers was not a key priority. However, in maintaining a healthy reserve margin, the Commission used concerns over reliability as justification for its policy of special tariffs for interruptible load (primarily large commercial and industrial customers).

The regulated approach was appropriate in an era when regulators were primarily concerned with controlling monopoly utility profits and the pace of technological innovation was slower than today. The restructured market combined with the promise of new technologies, however, gives retail customers a wider mix of resources to meet their needs in the future. The complexity of choices, including price options, now can reflect the diversity of consumer tastes, preferences, and their willingness to accept more risk to gain more reward. The customers now have the ability to shop for the best price or for energy generated from specific resources (e.g., wind) rather than having the Commission set rates for each class of customers.

Unfortunately, such expanded customer choice opens the door for free riding by competitive load and the retailers that serve them when it comes to risk management and public goods such as service reliability. In the deregulated ERCOT market, the Commission does not require that competitive retailers procure resources to serve their loads in the future. Because the ERCOT retail market is still relatively young, competitive retailers are uncertain about their market share and might be at a competitive disadvantage if they procure firm resources two or three years in the future when their competitors might not do so. In addition, competitive load has the financial incentive to buy from retailers with the lowest prices. The glut of generation that ERCOT has experienced until recently may have reinforced the desire of some retailers not to extend themselves with long-term contracts to serve load that they might not have in the future.

The Commission, within this paradigm, needs to address the maintenance of a prudent reserve margin that meets the reliability needs of ERCOT while avoiding unnecessary expenses to be imposed on customers due to excess capital investment and without excessively interfering with customer choice.

[4] An exception to this uniformity was an interruptible tariff for industrial load.

Features of a Resource Adequacy Mechanism

In its deliberations in the resource adequacy rulemaking, the Commission needs to balance a number of issues to ensure that ERCOT's reliability needs are met. Staff believes that any resource adequacy rule should do the following things:

- Ensure overall reliability of the grid.
- Create a sustainable resource adequacy mechanism that provides timely price signals for the development of new resources to meet future demand.
- Align market mitigation and the entry and exit of resources recognizing the necessary lead time for new entry.
- Address the impacts of inelastic supply and demand.
- Reduce uncertainty in projecting the reserve margin.

Ensuring Overall Reliability of the Grid

In the old world of regulated, vertically integrated utilities, the Commission would require utilities to maintain a planning reserve margin to ensure that demand would be met, and the utilities would recover the resulting costs through regulated rates. At present, the Commission does not enforce a reliability requirement on load serving entities similar to what the integrated utilities in the old regulated world had to meet. From the beginning of operation as a single control area on July 31, 2001 until the recent wave of plant retirements, the ERCOT wholesale market has enjoyed a reserve margin of greater than 20 percent because of the investor-led investment bubble, mostly in combined cycle plants, that occurred in response to the restructuring of the wholesale and retail electricity markets in ERCOT.

In the absence of a mandatory reserve requirement to serve end-use customers and in order to maximize profits by reducing unnecessary expenses or increasing market share, some competitive retailers may have strong incentives to minimize the amount of long-term capacity they secure for their business. This desire to maximize short-term profits may lead to underinvestment in "iron on the ground" at certain times in the electricity business cycle. Under the current market design, risk-taking retail electric providers (REPs) have the ability to lean heavily on the spot market (to extent their credit limits permit) rather than procuring resources through long-term contracts.[5] This free ridership arises from the fact that current market rules and the installed metering and control technologies do not allow the exclusion of those who do not pay for reserves from enjoying the benefits of reserves. The inability to exclude free riders is one of the fundamental characteristic of a public good, much like not being able to exclude those who refuse to pay for fire protection or national defense from enjoying the fruits of such preventive policies. To address this potential free rider problem in meeting the reliability needs of ERCOT, the Commission needs to provide incentives for the marketplace to ensure that sufficient resources exist to maintain the reliability of the ERCOT grid at a competitive cost.

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[5] Other reasons, including the nascency of the ERCOT market, rate of new entry and rapidly shifting market share in the retail market as well as uncertainty over future wholesale market design, also probably contribute to the reasons why retailers have not chosen to enter into many long-term bilateral contracts.

Creating a Sustainable Resource Adequacy Mechanism

Not only does ERCOT need sufficient resources to maintain reliability in real-time operations, ERCOT needs to work within the technical limitations of generation, dispatch, and transmission. As a result, any resource adequacy mechanism needs to ensure that the ERCOT operator has sufficient resources of the right type in the right places.

The Commission's resource adequacy mechanism will interact with other market features and regulatory requirements. All of these parameters must be consistent and function together to allow ERCOT and the market to develop:

- the most efficient mix of transmission and generation in load pockets in non-attainment areas,
- generation to provide voltage support at necessary spots on the grid,
- resources capable of providing the operators with real-time flexibility to meet intra-day changes in load and contingencies,
- innovative and efficient technologies, and
- demand-side resources.

A well-designed resource adequacy mechanism can help the market approach reliability in ways that more efficiently balance key elements of competition and reliability.

A resource adequacy mechanism also needs to take into account the following key issues in the ERCOT market:

- a successful and dynamic retail market,
- ERCOT's virtual isolation from other electrical interconnects,
- a heavy reliance on gas-fired capacity, particularly on the margin, and
- a very wide range of annual and daily levels of load that reflect significant variation in temperatures in Texas.

Aligning Market Mitigation and the Entry and Exit of Resources

Most wholesale electricity markets in the U.S., including ERCOT, have some form of offer caps and other forms of market failure mitigation measures to address price spikes or market failure. A consequence of too much mitigation is that it often suppresses legitimate scarcity rents and inframarginal profits. (See Appendix A for detailed descriptions of these two terms)

Practically speaking, scarcity rents and inframarginal profits are the margins needed above daily operating costs (i.e., short-run marginal costs) of resources that allow:

1. owners of existing resources to recover their fixed costs of refurbishing existing plants to keep them in operation and provide a fair market return on their capital (*i.e.*, the market equivalent of regulated rate of return), and

2. enable potential developers of new resources to pay the mortgage on money they must invest in order to put the new resource in operation.

In other words, scarcity rents represent the market mechanism needed to signal resource shortages and provide incentives for new investment in resources. [6] Furthermore, this mechanism allows the demand, through demand side offers, to determine how much generation capacity is needed. Mitigated energy prices that often suppress scarcity rents may be insufficient for resources to earn enough return to cover their fixed costs, a problem that can be described as the "missing money."[7] If left unattended, the market may experience significant shortages of generation during summer peak, leaving the market vulnerable to sustained high prices and possible involuntary load shedding. While load shedding by itself is not necessarily bad, economic efficiency dictates that market participants should not shed load whose cost of curtailment exceeds the marginal cost plus the amortized fixed cost of a peaking unit that could have been built.

In wholesale electricity markets today, we find two potentially sustainable approaches to resource adequacy that can address the "missing money" issue. PJM, NYISO, and ISO-NE ("East Coast markets") have a relatively low energy offer cap with payments for capacity (*i.e.*, a capacity-and-energy resource adequacy mechanism). Payments for capacity as envisioned in a resource adequacy mechanism could smooth the payment stream for resource owners and energy prices for consumers while creating more stability for investment in new capacity. In contrast, Australia has no capacity payments but a very high offer cap (*i.e.*, an energy-only resource adequacy mechanism). The offer cap of $AUS 10,000 can provide a strong incentive for resources to provide electricity service and for load to maintain forward supply contracts to avoid paying thousands of dollars per MWh when they are short in the spot market. The high offer caps in Australia have increased bilateral contracting between buyers and sellers, which has resulted in lower average spot market prices.[8]

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[6] For a more detailed discussion on the role of scarcity rents in resource adequacy, see Oren Shmuel S., "Ensuring Generation Adequacy in Competitive Electricity Markets", Chapter 10 in: **Electricity Deregulation**: *Choices and Challenges*, Griffin, M. James and Steven L. Puller, editors, (BSSEPP) Bush School Series in the Economics of Public Policy, June 2005.

[7] The term "missing money" was popularized by Dr. Roy Shanker. See "Comments of Roy J. Shanker, Ph.D., on Standard Market Design, Resource Adequacy Requirement," FERC Docket No. RM01-12-000, January 10, 2003.

[8] Staff communication with Peter Adams, Manager, Surveillance and Enforcement, National Electricity Code Administrator (Australia), February 1, 2005.

Table 1

	Capacity Payments	No Capacity Payments
$1,000 offer cap[9]	NEISO, NYISO, PJM	Alberta, ERCOT
$10,000 offer cap[10]	-------------	Australia

Based on the prices shown in Table 1, a number of market participants and economists have commented at Commission and TNT workshops that the ERCOT market design with existing price mitigation measures provide neither sufficiently high prices nor a capacity mechanism to provide ERCOT with timely construction of new resources or retention of existing resources. A recent white paper on the Alberta electricity market made the same observation about that market.[11]

The current market design in ERCOT also has limited long-term contracting, which in principle might provide a liquid forward market that would provide adequate forward support for resources. The protection provided to LSEs by the capped spot prices reduces (from their risk management perspective) the optimal quantity of forward contracts in their portfolios. Indeed, with capped spot prices LSEs would prefer to cover only a portion of their quantity risk with forward contracts and rely on the spot market to cover the difference between their peak load and their contracted amount. Consequently generators that provide planning reserves and "sit on the bench" most of the time waiting for the few peak demand hours with high energy prices during the year are not able to cover their fixed costs due to the capped spot prices during these hours. A higher offer cap would transfer more risk to LSEs and would provide incentives for them to cover a larger portion of the quantity risk through bilateral contracts, which in turn will increase supply.

Addressing the Impacts of Inelastic Supply and Demand

In a market, demand and supply respond to price. Higher prices reduce demand and increase supply. This responsiveness is called elasticity. Supply or demand is considered price elastic when small changes in price elicit sizeable changes in supply or demand. For instance, demand for non-essential or luxury goods and service, such as foreign recreational travel, are considered price elastic because consumers travel significantly

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[9] The Alberta offer cap is in Canadian dollars. A Canadian dollar is worth about $0.80 U.S. at current exchange rates.

[10] The offer cap is $AUS 10,000. An Australian dollar is worth between $US 0.75 to $US 0.80 at current exchange rates. The Australian market does limit the amount of money a resource can capture on a weekly basis, after which the $AUS 10,000 offer cap drops to $AUS 100.

[11] Alberta Department of Energy, *Refinement Options for Alberta's Wholesale and Retail Electric Markets*, March 10, 2005, pages 26-36.

more when the price of travel falls. Supply or demand is considered inelastic when large changes in price elicit little or no change in supply or demand.[12]

The economics of the wholesale electricity market are unique because the market has instances of severe demand-side inelasticity **and** supply-side inelasticity. Demand inelasticity sharply increases the number of short-term price spikes that can hinder the smooth operation of the market over time. An example of this phenomenon was the supply shortage in California that resulted in billions of dollars of scarcity rents being paid by customers and involuntary service interruptions. Demand side inelasticity is amplified by traditions of electric system supply operations that have evolved over time and reflects the "obligation to serve" all loads at an identical, mandated level of reliability.[13]

Supply inelasticity in a competitive market causes boom-and-bust cycles for electricity generators, which can lead to poor long-term investment decisions and insufficient capacity at certain points of the electricity business cycle. In order to sustain adequate generation capacity, the return on investment will need to be high enough to spur future building of new power plants. Economic theory suggests that electricity prices will rise as the reserve margin shrinks and long-run market equilibrium will prevail. However, the time lag in construction of new plants, imperfections in the capital market that may result in overreactions to credit risk and the risk that suppliers will abuse market power when reserve margins shrink can make the restoration of market equilibrium costly to consumers. The consequences could be politically unacceptable when load does not have the ability to respond to high prices in an efficient, orderly, and cost-competitive manner.

Eventually, prices will rise to the point where developers again will plan and build new capacity in the ERCOT market. However, it is difficult to foresee how quickly this new generation will arrive after prices rise, especially if the recent financial condition of most developers does not improve markedly. Developers of gas-fired plants in ERCOT need two to three years (including permitting and construction) to bring new generation on line. Two years of high prices (scarcity rents) that could result from the time lag to build new generation would leave the market subject to the exercise of market power and substantial wealth transfers from consumers to producers. In addition, because of the high prices, the market will be prone to another rush of building generation, which may lead to another crash in electricity prices when new generation comes on line. These strong cyclical swings in prices combined with the time lag required to build new generation will make ERCOT prone to continuing boom-and-bust cycles.

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[12] The classic example of a good that is supply inelastic is beachfront property in Texas. Nature has provided us with a limited amount of beaches. People could build artificial beachfronts, but such an undertaking would be expensive and require years of planning and effort.

[13] ERCOT uses a "one-in-ten-year" standard, which means that ERCOT would target a reserve ratio that would make it very improbable that ERCOT would be required to involuntary shed load for more than one day duration every ten years.

Reducing Uncertainty in Projecting the Reserve Margin

In 2005 the Generation Adequacy Task Force (GATF) has been attempting to revise the reserve margin calculation process that produces a five-year forecast of reserve margins. The GATF has struggled with this task because in the current ERCOT market, no one can state with any certainty what resources will be available to meet peak demand. The uncertainty includes the following:

1. *How many existing resources, which are on the cusp of economic viability at prevailing prices, will be available in the summer months*?

   Units that are in mothball may retire or may return to the market, but the current market design provides little incentive for resources with low capacity factors to enter or return into the market. Those resource owners don't have clear indications that future prices will be high enough to maintain the economic viability of those units in the future.

2. *What type of demand-side response will occur?*

   Though ERCOT staff will conduct econometric modeling with some price sensitive variables to forecast peak load in future years, the level of load response is speculative at best. Such response is dependent on the actual prices that will occur in the future. A $1,000 offer cap may not be high enough to elicit predictable demand response and thus maintain reliability without involuntary load shedding.

A resource adequacy mechanism would solve these issues. In a properly designed capacity-and-energy market, ERCOT would have the ability to predict what capacity would be committed to the market provided that resources receiving capacity payments are under obligation to offer or deliver energy in the wholesale market for firm load. In an energy-only market, on the other hand, such predictability can be achieved if the reward for resources and the risk for load is so high that suppliers would have incentives to make offers into the market without a regulatory requirement, while load will be motivated to contract for resources (both generation and demand-side) as a shield or hedge against high energy prices.[14]

Benefits of an Energy-Only Resource Adequacy Mechanism

An energy-only resource adequacy mechanism would offer four potential benefits. This approach:

[14] Please note, however, that without the appropriate oversight, some risk-taking retailers might enter or expand in the ERCOT market without contracting with sufficient resources. These risk-takers could undermine the resource adequacy mechanism unless the Commission or ERCOT enacted the appropriate mix of credit requirements and oversight.

- Avoids problems associated with a capacity-and-energy approach (such as those listed below),
- Provides a range of risk/return tradeoffs for the market,
- Encourages competition for generating units with low capacity factors, and
- Increases elasticity of demand for electricity.

Avoids Problems Associated with a Capacity-and-Energy Approach

While capacity-and-energy markets, in theory, provide generation with sufficient market signals to enter and exit a wholesale market, experience with the capacity-and-energy approach in the East Coast markets has raised questions concerning the application of this approach:

- A corollary of using a capacity mechanism has been the requirement for resource owners to offer their resources into the market at or near their short-run marginal cost (SRMC) because capacity payments would cover their fixed costs.[15] On average, this type of mitigation would produce prices in spot markets close to SRMC could undermine the very price signal that might provide incentives for the implementation of technological advances that would help the electricity market mature.
- Proposed and enacted changes to existing capacity-and-energy mechanisms in East Coast markets appear to have become increasingly administrative and complicated.
- Capacity payments reward owners of incumbent generation but may not necessarily provide incentives for new investment since the capacity products are too short term to enable participation of new entrants in capacity markets. While capacity markets might be good at keeping existing generation online, the evidence is not clear that capacity payments provide the appropriate incentives for new generation to interconnect in the right places.

Provides Better Risk/Return Tradeoffs

One key motive for deregulation of the electricity industry in Texas was to devolve decision-making. Under Senate Bill 7 (SB 7), the Commission oversees, not manages, the electricity market. Decentralized decision-making based on economic forces is one of the key features of a successful market. Generally, a good price mechanism is vastly preferable to an administrative dictum, because market participants should have the flexibility to choose the most cost-effective solution.

Utilities under regulation could earn specified rates of return at minimal risk, as compared to the different mix of risk and return that each market participant has under

[15] Some market participants in the East Coast markets have disputed whether these markets actually see prices near SRMC. Market mitigation policies in East Coast markets do allow resource owners to make offers that include a margin above estimated SRMC. Also, a complement to this type of resource-specific mitigation could be an administratively-determined mechanism to reflect scarcity pricing in the market that would allow the market to respond quickly to unanticipated contingencies on the grid. The Texas Nodal market design includes such a scarcity pricing mechanism, whereby ERCOT can deploy a limited number of responsive reserves in real-time with an adder to gradually increase the market clearing price in the real-time market to the $1,000 offer cap.

deregulation. Those market participants willing to implement and market new technologies should be willing to take more risk than the integrated utilities for a potentially greater but uncertain reward. For efficient deployment of new technologies, market participants who have the skill to handle risk/return tradeoffs inherent in a market should receive the appropriate rewards. Deregulated prices are part of the needed market signals that allow these risk takers to enter the market.

Putting increased price risk on retailers could spur innovation and creativity in developing means to hedge that risk, maturing the market by increasing elasticity of demand through deployment of new technology. A by-product of more elastic demand could be the reduction of potential market power concerns associated with the ERCOT spot markets and with the capacity-and-energy resource adequacy mechanism used in the East Coast markets.

The promotion and adoption of new, cost-effective technologies is one of the reasons that drove the Texas Legislature to deregulate electricity generation and sales. The promise of deregulation is to provide consumers with a wider array of options for their electricity service. The Commission and ERCOT stakeholder committees should create the conditions that encourage the interaction of new technologies and diverse consumer preferences with the market forces in ERCOT. The possibility of high prices during shortages would provide a substantial reward for investors who are willing to take substantial risks in deploying and marketing new resources.[16]

Encourages Competition for Generating Units with Low Capacity Factors

In the regulated world, the rates that customers paid included implicit capacity payments for generating units regardless of whether they were used continuously as baseload units or only a few times a year as peaking units. Although the Commission, like other state regulators, required utility assets to be used and useful, the justification for new units presumed an obligation to serve and that all customers, except interruptible customers, were entitled to firm service. By determining an identical, fixed level of reliability of electricity service for each customer, the Commission implicitly set a value of reliability that was based on statutory and policy decisions and quantified in terms of engineering criteria.

In a deregulated market, units with low capacity factors need to earn sufficient revenues to be kept online; however, they may not earn enough money because a number of market participants do not wish to pay for a very high level of reliability or are not required to do so by a Commission rule or ERCOT protocol.

In reality, if the price of electric service rises to a certain level, some market participants may be willing to curtail their electric service voluntarily for a number of hours each year

[16] The possibility of scarcity rents embedded in the future spot market prices might provide incentives for load-serving entities to enter into bilateral contracts with resource owners to develop new generation. Those bilateral contracts would provide sufficient funds to cover the fixed costs of deploying the new resources.

rather to pay peaking units to deliver that power during those high-priced hours. These market participants would consider the old standard of reliability inappropriate for their needs, for at least a portion of their electric service. An efficient market design would reflect the different values of reliability (interruptibility) they place on a portion of their electric service by letting market prices reflect those preferences.

Under an energy-only resource adequacy mechanism, high offer caps could provide needed potential "headroom" for commercial and industrial loads, in the form of loads acting as resources (LaaRs), to compete with the traditional peaking units, the old standby of the regulated era that can sit idle for 90 percent or more of the year. This competition with traditional peaking units would take place in the real-time energy and ancillary services markets in a number of ways: easing ramping constraints in the market, managing load during summer peaks, and providing backup to the system operator in the form of ancillary services beyond the current procurement as responsive reserves.

The possibility of high prices combined with new technologies could provide incentives for smaller loads to increase their deployment of alternatives such as solar panels, energy efficiency appliances, and direct load control (DLC) programs.[17] Higher summertime prices, combined with time-of-use (TOU) pricing for a variety of customers, including residential customers, would provide stronger incentives for installing energy-efficient air conditioning or increasing insulation of buildings and homes.[18]

Solar power facilities would become more valuable to be part of the optimal fuel mix because of their ability to generate power during peak usage. The potential higher real-time prices during peak hours would give higher rewards to generators that can produce energy during peak conditions without the pollution associated with thermal peaking units. Such a service could be useful in non-attainment areas within ERCOT.

Increases Elasticity of Demand for Electricity

One of the current problems in restructured electricity markets is the highly inelastic demand for electricity among all but the largest consumers. Such inelastic demand requires a substantial *generation* (as opposed to *resource*) reserve margin.[19] When the generation reserve margin falls, an electricity market is vulnerable not only to high prices (e.g., scarcity pricing) but abuse of market power, because differentiating between scarcity pricing and market power abuse is difficult to prove after the fact.

[17] An example of a direct load control program is an air conditioning cycling program. When prices and demand rise to a certain level or when ERCOT declares an emergency condition, a device on an air conditioner receives a signal which turns off the air conditioner for a certain amount of time.

[18] Time-of-use pricing, with predetermined rates reflecting higher average costs of generation electricity over peak summer hours, would be a safer way for residential load to be exposed to price risk. Large industrial and commercial customers might be in a better position to take the greater risks and reap the greater rewards involved in real-time pricing.

[19] Resources are a combination of generation and demand-side resources (e.g., LaaRs, participants in DLC programs).

An energy-only resource adequacy mechanism increases the rewards for demand-side participation, and as a result makes the demand for electricity more elastic. The increased participation of registered demand-side resources over time would provide a flexible cushion that would reduce the price volatility involved in the integration of new generation over time. Encouraging "reliability at a price" through voluntary, price-sensitive load shedding would allow market participants to more efficiently reflect their value of reliability while maintaining the overall reliability of the grid.

Demand-side resources that are available for deployment when prices are high because of a low generation reserve margin, could serve as a shock absorber for end-use customers in the face of the time lag of building new power plants. The amount of demand-side resources that would enter the market in a given year would be a function of anticipated prices and would complement the entry and exit of generation resources. The thinner the generation margin, the higher market prices would be, which would provide more demand response. As more generation entered the market, the larger the generation margin, lowering market prices, and reducing the participation of demand resources in the market during that year. An energy-only resource adequacy mechanism would require widespread and active participation of demand-side resources in order to be an improvement over the situation in the Australian market, where the lack of dedicated demand-side resources has made voluntary load shedding in Australia expensive when the generation reserve margin shrinks.[20]

Issues and Potential Concerns Related to an Energy-Only Resource Adequacy Mechanism

The energy-only resource adequacy mechanism is not free of shortcomings. In addition, in order to implement such mechanism, the Commission should address certain transitional issues in order to make energy-only resource adequacy mechanism to work successfully. the following sub-sections provide a brief discussion of some potential concerns will be provided. Following this discussion, this paper presents a list of possible issues related to an energy-only resource adequacy mechanism. The list is not exhaustive but is meant to highlight a number of transitional issues or interactions with the overall market design in ERCOT that the Commission may need to address if it wishes to pursue an energy-only resource adequacy mechanism.

Potential Concerns about Using an Energy-Only Approach

While an energy-only resource adequacy mechanism could provide benefits to the ERCOT market, such an approach has the following risks and trade-offs:

- Price spikes in the real-time market could be a magnitude greater in size than the market experiences today, which in turn could encourage more market power

[20] Staff communication with Peter Adams, Manager, Surveillance and Enforcement, National Electricity Code Administrator (Australia), February 1, 2005.

abuse. The Commission and ERCOT might need to institute tighter automated *ex ante* market mitigation mechanisms, increased market monitoring, and tougher enforcement provisions as a result.

- Credit risks likely would increase for retailers and other LSEs. The Commission would need to ensure that LSEs maintained the appropriate credit standards so they could manage higher price volatility while offering sufficient price stability to end-use customers.
- For an energy-only resource adequacy mechanism to work efficiently, the market would need widespread and active participation of demand-side resources to provide a dependable response to price signals over time. Because demand-side participation would have to be significantly greater than the ERCOT market has seen to date, the Commission and ERCOT would need to make a long-term commitment to develop the necessary rules, protocols, and infrastructure that would encourage such demand-side participation.

Market Mitigation

An energy-only market does not mean abandoning consumers. Because price spikes could be substantially higher under an energy-only mechanism, the Commission would have an even greater need to make a policy decision that would distinguish the difference between scarcity pricing and market power abuse by using a rigorous *ex ante* market mitigation mechanism. The big problem, as was seen in the California crisis, is that a market monitor may find it very difficult to prove after-the-fact that the high prices were legitimate scarcity rents rather than the impact of market power abuse. Therefore, the Commission and ERCOT would need to supplement this *ex ante* market mitigation approach with substantial market monitoring resources to proactively address potential market power abuses.

The Commission would continue to protect those consumers impacted by local constraints that enhance opportunities for abuse of market power. In particular, market mitigation needs to mitigate high prices associated with potential market power abuses, associated with local constraints while still providing scarcity pricing for system-wide shortages.[21]

The time lag between the market price signal and the entry of new generation complicate market mitigation that, if unchecked, could lead to significant transfers of wealth to generators. ERCOT should have some limit on the earnings associated with very high offer caps to ensure scarcity pricing without price gouging. For instance, in the Australian market, the amount of money a resource can capture on a weekly basis is limited. When the limit is reached, the resource's $AUS 10,000 offer cap drops to $AUS 100. Having such a cumulative cap in ERCOT, however, could create a bright line which enables pivotal suppliers to collect the allowed rents while staying within the allowed limits. Any market mitigation approach would need to address the problem of pivotal suppliers in the ERCOT market.

[21] Stakeholders have developed a variation of such a mitigation plan in the proposed Texas Nodal protocols.

Load Serving Entities (LSEs)

Credit and Oversight

Under an energy-only resource adequacy mechanism, the Commission might have to increase oversight of LSE credit and wholesale contracting issues to avoid the unintended consequences of a significant “free rider” problem. Some LSEs may not secure sufficient forward positions to match the load they serve over time or sufficient credit to deal with price increases, in the event the level of demand approaches available supply. For example, a few retailers could chose to gain market share quickly by taking advantage of low spot market prices without backing their commitments to retail customers with forward positions in the wholesale market. As a result, the market might be left without sufficient reserves and without price signals indicating to PGCs the future demand for power. The resulting shortage of reserves and high prices could cascade into a problem that could negatively impact the entire market.

To prevent such an outcome, the Commission or ERCOT could tighten credit ratings for LSEs or increase oversight of LSE’s credit risk, similar to mandatory reserve requirements in the banking industry that prevent the failure of a bank that is over-extended and suffering losses from melting down the entire financial system. As with the banking industry, the Commission would need to ensure that LSEs meet some minimum threshold of risk management by setting aside some financial reserves to meet their projected load or by producing evidence of equivalent coverage through bilateral contracts. However, increased credit requirements would increase the cost of operating in the market, which could reduce the number of competitors, particularly startups.

To avoid insufficient procurement of resources by the market as a whole, the Commission could require credit standards that would encourage LSEs to forward contract some or all of their projected loads during a transition period, as was done in the Australian market. Forward contracts could take the form of energy contracts or options on specific resources. To mitigate potential exercise of market power in the bilateral contract market, contracting obligations between LSEs and resource owners should be sufficiently forward-looking so as to allow new entrants to compete with existing resources and have sufficient lead time to meet their contracting obligation with new construction. The Commission could temper the requirement over time if it deemed sufficient the amount of demand-side resources and peaking capacity that are proven available and sufficient to respond to high market prices (*e.g.*, $10,000 offer caps). A contractual link between a resource and load might not be necessary at that time assuming that such high prices provide a strong incentive for demand-side resources and peaking units to participate.

Long-term Contracting

LSEs would be less likely to lean on the spot market when the offer cap is set at $10,000. The Australian market has 90 percent bilateral contracting despite very low real-time prices, though market concentration in the Australian retail market may play a role in this limited use of the spot market.[22] As is done in the Australian market, LSEs would buy options on peaking units that have fast start times and fast ramping capability to reduce the amount of energy the LSEs would need to buy in the spot market when spot market prices were very high. [23] These options on peaking units are essentially a market-based capacity mechanism embedded in a bilateral contract.

Providing incentives for market participants to interconnect a broader mix of resources through bilateral contracts could lower the cost of meeting ERCOT's reliability requirements. For instance, market participants interconnected mostly combined cycle units in the first few years of the ERCOT market, reflecting the low heat rates of those generating units compared to existing gas-fired steam boilers or small, quick-start gas turbines. The market, however, may not provided resource owners with sufficient financial incentives to invest in capacity that had higher heat rates but faster starting and ramping capability. As a result ERCOT may currently not have the most cost-effective mix of resources to manage real-time load fluctuations and transmission contingencies.

Capacity payments embedded in these option contracts would be market-based with demand-side resources competing with traditional peaking units for these contracts. Market participants would determine strike price/capacity combinations continuously in the market with the appropriate level of credit oversight from either ERCOT or the Commission. In contrast, a capacity-and-energy mechanism required through a centralized auction, such as those seen in East Coast markets inherently relies on a heavily-mitigated annual auction with a "one-size-fits-all" risk / return mechanism. A regulated market with captive load would be better served by this approach than a deregulated retail market. The advantage of such contracting obligations over introducing capacity products as seen in the East Coast markets is that the Commission enforces as a transitory measure something that a healthy market would do on its own. Hence, as the market matures, the enforcement can be relaxed. By contrast, introducing capacity products could be problematic because they would be hard to remove at a later date as the resource owners that benefit from capacity products would oppose change.

Demand-Side Resources

Demand-side resources could become more cost-effective than peaking units in providing certain ancillary services, meeting peak energy demand, and as a hedge against high prices. Retailers could offer a variety of products, such as TOU pricing and DLC programs (to provide ERCOT with an offer curve based on the curtailment of power to hundreds or thousands of residential and small commercial customers). TOU pricing for residential customers could be useful information for simplified price response that would provide price signals with reduced risk compared to larger commercial and

[22] The Australian retail market is dominated by a few large retailers that engage in limited price competition. Staff communication with Peter Adams, Manager, Surveillance and Enforcement, National Electricity Code Administrator (Australia), February 1, 2005.

[23] In the Australian market, peaking units are offered into the market at around $AUS 300 and $AUS 10,000, depending on whether the unit is serving as a hedge for load (at $AUS 300) or is entering the market speculatively ($AUS 10, 000). Source: Staff communication with Peter Adams, Manager, Surveillance and Enforcement, National Electricity Code Administrator (Australia), February 1, 2005.

industrial customers that would be in a position to respond to real-time prices. A centralized day-ahead market would increase the effectiveness of demand-side resources, as these resources would have an easier time deploying in real-time by having standing offers in a day-ahead market that ERCOT could optimize over a 24-hour period.

As part of a transition to a sustainable energy-only resource adequacy mechanism, the Commission would need to ensure that ERCOT protocols and market design were capable of handling the various engineering and market details such as proper interconnection and metering standards for demand-side resources that rely on the participation of small commercial and residential customers, appropriate load profiles, enforcement of high standards in measuring and tracking the output of deployed demand-side resources, and verification of the available capacity of demand-side resources that rely on the curtailment of retail customers who can switch providers.

Demand-side participation would have to be significantly greater than the ERCOT and Australian markets have seen to date. ERCOT would need to ensure that demand-side resources would be available in sufficient numbers to provide sufficient competition to generation during summer peak. The ERCOT market would need widespread and active participation of demand-side resources to provide a dependable response to price signals over time. Active participation is important, because developers of gas-fired plants in ERCOT need at least two to three years (including permitting and construction) to bring new generation on line. Two years of high prices (scarcity rents) that could result from the time lag to build new generation would leave the ERCOT market subject to the exercise of market power in the face of insufficient demand-side response.

The potential for higher price spikes under an energy-only resource adequacy mechanism could provide owners of generation with stronger incentives to physically withhold some their units from the spot market to increase prices for their remaining fleet that they are offering into the spot market. The active participation of demand-side resources in the spot market would be needed to undermine this gaming strategy by weakening the market power of generators.

Installing Advanced Meters

The Commission should consider encouraging utilities to install advanced meters for price-to-beat customers in large urban areas, where the opportunities to add generation or transmission capacity are limited and expensive, in order to enable time-of-use or near real-time pricing for those customers. Retailers could provide a variety of options to those customers that would encourage peak-shaving and other demand-side responses to pricing signals in an energy-only market.

The Commission also could consider lowering the requirement for interval data recording (IDR) meters from the soon-to-be implemented 700 kW threshold to a lower value to encourage more demand-response in the ERCOT market.[24] Furthermore, the

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[24] The requirement takes effect on October 1, 2005.

Commission can require ERCOT to utilize load profiles that enhance settlement of customers with load response capabilities.

Generation Alternatives to Transmission

Even under an energy-only resource adequacy mechanism, a number of transmission contingency, voltage, or operational issues may continue to evade market signals / price mechanisms.[25] Most times, ERCOT finds a permanent solution for these problems involving the installation of new transmission lines or equipment.

Many of these problems may require an interim or long-term solution involving the operation of nearby generation that cannot operate at the required level with prevailing market prices. These generation solutions fall into the following continuum:

OOMC (day-ahead use of resource) → RMR (seasonal / annual use of resource) → Locational Installed Capacity [LICAP] (long-term contract with resource currently proposed in some East Coast electricity markets)

East Coast electricity markets have proposed adding locational elements to their installed capacity markets to address these transmission-related problems. The Commission could address such alternatives as part of transmission policy and not need to fold this issue into a resource adequacy mechanism. For instance, ERCOT could enter into an annual RMR as an interim step to a transmission solution. ERCOT also could enter into a long-term LICAP contract with a generation unit as a substitute for building transmission at a particular site if such an arrangement were cost-effective. Such a contract with a generator could include a must-offer requirement with a low offer cap for that unit, as allowed currently in the ERCOT protocols.

Publication of the Statement of Opportunities Report for Resource Deployment in ERCOT

After the Texas Legislature passed SB 7 in 1999, generation owners interconnected about 30,000 MW of new generation capacity in ERCOT. The problem with this mass entry of new resources in the 1999-2003 period was that almost every new generating unit was either a baseload unit or wind resource, and it was not always in an appropriate location. The first flush of opportunity to invest in the market blinded market participants from identifying profit opportunities in the various requirements of running an electric grid (e.g., resource's location, ramping capability, and minimum loading).

ERCOT and the Commission could assist market participants in a market with an energy-only resource adequacy mechanism by providing an annual detailed assessment of ERCOT's future needs and let market forces optimize solutions to identified problems and opportunities as opposed to providing just a reserve number. Australian regulators

[25] Both the proposed locational installed capacity mechanism (LICAP) in ISO-NE and the proposed Reliability Pricing Mechanism in PJM incorporate some of these transmission-related elements.

and the grid operator provide the Australian market with such a report, called a Statement of Opportunities (SOO).

The SOO could identify potential gaps in ancillary services, ramping capability, baseload resources, transmission losses, and resources with low capacity factors from one to ten years forward. The SOO would disseminate information such as load duration curves. Market participants could use this information to determine which type of units to build and where to build. A combination of an SOO and an energy-only adequacy mechanism could accomplish what PJM's Reliability Pricing Model (RPM) is attempting to do. The market would be more flexible in response to changing conditions than the RPM, which picks winners among resources four years ahead of time. Using a market mechanism rather than an optimization routine would open development of resources to more competition and would be less susceptible to market power issues associated with a centralized auction.

Appendix A
Descriptions of Scarcity Rents and Inframarginal Profits

Scarcity rents**:** In a competitive unrestricted market, scarcity rent is the difference between the value to consumers of the most expansive MW that cannot be supplied due to limited generation capacity (i.e. the marginal demand side offer accepted) and the marginal cost of the most expansive MW served. In a long-run equilibrium, if we allow generators to collect such scarcity rents by letting demand side bids to set the clearing prices, the scarcity rents should be exactly what are required to cover the amortized fixed cost of the marginal generating unit.

By definition scarcity implies that marginal prices are set by unserved load (demand offers) while supply side offers reflect marginal cost of supply. In the presence of market power, however, suppliers may attempt to capture rents under shortage or near shortage conditions by raising prices through economic withholding strategies or "hockey stick bidding". While the resulting market clearing prices in such cases may reflect scarcity it is impossible under such circumstances to differentiate legitimate scarcity rents from economic withholding markups.

Inframarginal profits**:** Generators that are not on the margin and whose capacity cost is typically lower than that of peaking units on the margin recover their amortized fixed capacity cost from inframarginal profits (*i.e.*, the difference between the MCPE and their marginal cost) plus the scarcity rents. This payment above marginal cost will both insure generation capacity adequacy and an optimal technology mix of generation.

CERTIFICATE OF SERVICE

I hereby certify that I have served, by electronic and United States mail, a Notice of Availability of the Opening Comments of The California Independent System Operator Corporation on The California Public Utilities Commission's Capacity Markets White Paper to each party in Docket No. R.04-04-003.

Executed on September 23, 2005, at Folsom, California.

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