California Public Utilities Commission

Capacity Markets White Paper

August 25, 2005

CPUC Energy Division
Sean Gallagher, Director

202004

TABLE OF CONTENTS

I. INTRODUCTION

This White Paper has been developed by Energy Division Staff in accord with an Assigned Commissioner's Ruling in the Commission's Resource Adequacy Proceeding[1] issued on February 28, 2005 ("February ACR").

Through its Resource Adequacy Proceeding, this Commission has required the State's CPUC-jurisdictional load serving entities (LSEs) to procure the bulk of their wholesale electric needs through forward procurement mechanisms. The Commission refers to these mandates as resource adequacy (RA) requirements. The RA requirements mandate that jurisdictional LSEs acquire qualifying capacity to meet a planning reserve margin (PRM) of 15-17% by June 1, 2006.[2] LSEs are required to demonstrate 90% compliance for the five summer months a year in advance, and 100% compliance on a month-ahead basis for every month of the year. Additional details of this procurement obligation, including how the obligation will be enforced and proposed penalties for non-compliance, are currently being addressed in "Phase II" of the Resource Adequacy Proceeding.

The primary purposes of the Commission's RA requirements are: (1) to ensure sufficient incentives for new electric infrastructure investment, and maintenance of necessary existing generation, by providing a revenue stream that is missing from today's capped energy markets to compensate generation owners for their fixed costs; (2) to ensure that this investment is provided in a way that minimizes total consumer cost of delivered power over the long run; and (3) to ensure that the induced investments are available when needed for reliability. This requires as a first step the adoption of a reliability standard along with a procedure for determining the capacity required to meet it. Then, after inducing the right

---

[1] *Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Planning,* Rulemaking 04-04-003 (April 1, 2004).

[2] *Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development* "Interim Opinion", Decision No. 04-01-050 (January 22, 2004) and Resource Adequacy Proceeding "Interim Opinion Regarding Resource Adequacy", Decision No. 04-10-035 (October 28, 2004).

level of capacity investment, it is equally important to assure that such capacity is available, particularly during emergency conditions.

Recognizing the objectives of the Commission's RA requirements, and the potential for an organized capacity market to complement them, President Peevey issued the February ACR instructing Commission staff to evaluate certain existing organized capacity markets[3] and how development of an organized capacity market in California might "complement and aid in the effectiveness of the Commission's Resource Adequacy program in several ways," including:

a) A centrally administered residual market could enable energy service providers (ESPs) and other LSEs with smaller scale reserve requirements to meet their resource adequacy requirement in a cost-effective manner. For sellers that may not want to transact for very small quantities of capacity, a market could provide a simple, efficient means to sell capacity.

b) In contrast to bilateral-only markets for capacity, adding a centralized California Independent System Operator (CAISO) market could allow for a more effective means of market monitoring and market power mitigation as well as providing a visible market price.

c) Compared to reliability-must-run (RMR) contracts, a capacity market, especially one with locational attributes, could provide the CAISO with a more cost-effective means to access the resources it needs, without interfering with LSE procurement.

d) A capacity market may provide LSEs with a means of addressing "load migration" concerns and reducing stranded costs by allowing the refining and shaping of capacity procurement quantities and the managing of resource portfolios.

e) A centralized capacity market may make compliance and enforcement of the RA requirement more manageable.

[3] As used in this paper, the term "capacity market" refers to bilateral contract and organized capacity markets, such as those operated by the regional transmission organizations in New England, New York, and PJM (Pennsylvania-New Jersey-Maryland) that allow participants to purchase or sell capacity products which meet reliability requirements. (Refer to Section X. Glossary of Terms.)

The February ACR also noted that any actions taken in Phase II of the Resource Adequacy Proceeding should allow for the potential development of a capacity market framework.

The Commission's October 2004 decision in its Resource Adequacy Proceeding (D.04-10-035), established a capacity, as opposed to an energy-only, paradigm. In addition, the Commission has adopted various Resource Adequacy features consistent with development of a capacity market, namely a requirement that 100% of the RAR must be met in the month ahead timeframe, and locational capacity requirements. What the Commission must decide is whether it supports a public centralized capacity market in addition to the private bilateral markets as a means of efficiently and effectively implementing the Resource Adequacy requirements adopted broadly in October and which are being finalized in the forthcoming Resource Adequacy Phase II Decision.

In response to the February ACR, this White Paper outlines the issues, advantages and potential problems that should be considered in adopting, designing and implementing an organized capacity market in California, recognizing the RA requirements that have already been established, and the Commission's goals in adopting those requirements. It then reviews the capacity markets established in the New York, New England, and Pennsylvania-New Jersey-Maryland (PJM) regional transmission organizations. Finally, this White Paper provides Staff's recommendations with respect to adopting and designing capacity markets for California, and identifies issues related to the appropriate roles of both the Commission and the CAISO in the establishment and operation of an organized capacity market.

This is a Staff White Paper. It is not intended to represent the views of Commissioners, but rather to inform those views. It is intended that this White Paper will aid as a guide for a high level discussion of the issues. Based on this discussion and receipt of new information, Staff may further develop and/or refine its position over time.

II. EXECUTIVE SUMMARY

Introduction

The Commission has established a capacity-based, as opposed to an energy-only, paradigm for Resource Adequacy, and has ordered the State's CPUC-jurisdictional load serving entities (LSEs) to procure the bulk of the State's wholesale electric needs through forward procurement mechanisms. Adopting an organized spot capacity market could complement California's existing Resource Adequacy Requirements and provide benefits to the state, including more effectively driving new investment, controlling market power, reducing risk premiums, and enabling LSEs to more efficiently comply with their Resource Adequacy obligations. At the direction of President Peevey, Commission staff has completed its initial investigation into the issues which must be considered in determining whether and how to adopt such a market.

A review of the various sections of the initial investigation follows:

Why Capacity Markets—Structural Problems and Their Impacts

This section provides a brief overview of two structural problems inherent in the existing energy market and their impacts that preclude a workably competitive market. Basic economic theory predicts that a workably competitive energy market will provide price signals and sufficient revenues to induce an efficient level of investment in generation (e.g. both fixed and variable costs); provide generators the right incentives to produce when and where they are needed (i.e. generators should not withhold generation); give consumers, the right incentives for demand-side response; and provide buyers and sellers with the right incentives to hedge price volatility (i.e. engage in long term contracting). In such an energy market an RA requirement is unnecessary.

Unfortunately, two significant structural imperfections on the demand side, and their resulting impacts, prevent the existing energy markets from inducing the investment necessary to ensure a target level of generation adequacy. Most consumers do not have the tools to engage in meaningful demand response to high prices. In simple economic terms, current demand for electricity is virtually price inelastic. A second problem is that during shortage conditions the system operator is unable to selectively interrupt a consumer who has not paid his reliability bill. Consequently, it is impossible to sell reliability or to impose the costs of an LSE's negligence on the LSE's customers. Damaging side effects of these two structural problems are market power, investor risk, and a broken link between fixed cost recovery and the desired level of installed capacity. In other words, there is no relationship between today's energy market-clearing prices and the amount of installed capacity (i.e. generation in the ground) consumers are willing to support. Market prices cannot yet send the appropriate investment signals without regulatory guidance.

Because the structural market imperfections and adverse impacts cannot be fixed within a reasonable time frame, the regulator must step in with Resource Adequacy (RA) programs to induce adequate investment in production capacity.

Eventually, electricity markets are expected to develop sufficient demand responsiveness to balance supply and demand in real time. Eventually, it may also become possible to curtail individual customers on the basis of their energy contracts or requested reliability level. However, until these advance market structures are in place, markets cannot solve the reliability problem, and the task of inducing the adequate level of capacity for reliability will fall to the regulator. This is the fundamental reason for today's resource adequacy requirement, but there are other potential and important benefits as well.

How a Well Designed Capacity Market Compensates for Energy Market Imperfections

In response to these structural problems and related impacts, a well designed capacity market complements the Commission's objectives to fully implement the Commission's RA policy in the following ways:

1. Stabilize and guide existing markets to provide the target level of generation adequacy at a reasonable cost. It does this by drawing on the relationship between fixed cost recovery and the level of installed capacity;
2. Efficiently restore the revenues missing from the capped energy market;
3. Reduce both investor risk and market power;
4. Ensure against double payment in the energy and capacity markets;

5. Ensure generation performance by ensuring installed generation is available when it is needed;
6. Provide an effective means for the Commission to monitor and enforce compliance with its RA requirements;
7. Address free rider concerns associated with the implementation of retail choice; and
8. Work closely with the CAISO's proposed locational spot energy market to ensure generation locates where it is needed, and not in the areas that are inaccessible to load.

Potential Limitations of a Capacity Market—Fact or Fiction?

Common perceptions exist about the potential limitations of a capacity market. This section explores what these notions are and whether or not they are valid including:

1. Will a central spot capacity market interfere with bilateral trading?
2. Do capacity markets alone provide an adequate foundation for investment? Are they untested?
3. Since a capacity market approach relies partially on a regulatory scheme, should it be considered a pure administrative mechanism?
4. Do California's unique characteristics preclude it from being a suitable candidate for a capacity market approach?

Capacity Market Alternatives—Existing and Evolving Designs

The recent design innovation in capacity market design is the use of a demand curve with a non-vertical slope. This has been tested in New York, approved for ISO-NE by the ALJ and will be part of PJM's new proposal. This section provides a conceptual discussion of the administratively set demand curve, and then describes the capacity market designs in New York, PJM and New England that are in various stages of development and implementation. This section also introduces a framework for discussion regarding lessons learned and related policy questions.

Lessons Learned and Related Policy Questions

As capacity markets have evolved over the last seven years in the East, a number of lessons have been learned including the following:

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 provides for 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 for California from the experiences from other states and ISO/RTOs include:

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 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 energy and capacity market power concerns? What are other appropriate steps (e.g. subtraction of peak energy rents)?

Energy Division Recommendations

Based on a review of the structural problems and related impacts, how a well defined capacity market compensates for energy market imperfections, and a review of Eastern market models, Energy Division staff makes the following recommendations.

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

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.

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

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

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

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

Recommendation 7: Make the fixed-cost recovery curve explicit.

Recommendation 8: Strive for regulatory credibility.

Interagency Implementation

The Commission and CAISO have a key role in policy development and implementation of potential capacity markets and will continue to collaborate via a stakeholder process. However questions remain as to the extent to which the Commission should move beyond broad policy statements and set specific capacity market requirements, such as demand curve parameters.

Next Steps and Invitation to Comment

This paper is intended to be the first step in responding to President Peevey's February ACR. This paper presents staff's initial assessments and recommendations. In order for staff to more fully inform the Commission, and to move the process forward, staff seeks comments from interested entities. Comments may address any issue in the paper, but should focus on:

1) "Lessons Learned and Related Policy Questions" outlined in Section VI. E.

2) Staff's recommendations outlined in Section VII;

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

4) Any other significant issues not addressed above.

Staff requests that any comments be submitted by September 23, 2005 and any reply comments be submitted by October 10, 2005. Comments should be submitted in compliance with the procedure set forth in the Ruling providing Notice of Availability of this White Paper, dated August 25, 2005.

Upon receipt of comments, Staff will make further recommendations to the Commission, including a recommendation on an appropriate process for moving forward with the investigation of capacity markets (e.g. a Commission-initiated order initiating rulemaking, CAISO/FERC-initiated process, or another alternative).

III. WHY CAPACITY MARKETS—STRUCTURAL PROBLEMS AND THEIR IMPACTS

A. There Are Two Demand Side Structural Problems That Prevent The Existing Market From Inducing An Efficient Level Of Investment In Generation.

Basic economic theory predicts that a workably competitive energy market will provide price signals and sufficient revenues to induce an efficient level of investment in generation (e.g. both fixed and variable costs); provide generators the right incentives to produce when and where they are needed (i.e. generators should not withhold generation); give consumers the right incentives for demand-side response (i.e. conservation); and provide buyers and sellers with the right incentives to hedge price volatility (i.e. engage in long term contracting). In such an energy market an RA requirement is unnecessary.

Unfortunately, two significant structural imperfections on the demand side, and their resulting impacts, prevent the market from inducing the investment necessary to ensure a target level of generation adequacy. The two structural market problems are lack of demand response to real time prices, and independent system operator (ISO) inability to shut down service to specific customers creating a free rider problem:

1. Lack of demand response to real time prices.

Retail consumers are unable to adjust their demand to escalating real time prices for two reasons: First, today's consumers do not face the spot marginal price of wholesale energy. Second, most consumers do not currently have access to real-time metering. As such, they have no ability to adjust their demand to respond to prices. In other words, they have no idea what energy is selling for on the spot market, and have no ability to reduce their bills by cutting back their usage when prices escalate.

This problem is compounded by the fact that when desired demand outstrips available capacity, prices can rise indefinitely with no corresponding increase in capacity nor corresponding decrease in demand. The inability of demand to respond to shortage conditions (and the inability of demand to establish the shortage price) results in a market that literally cannot produce prices during shortage conditions. (See Figure 1.)[4] Instead prices must be administratively determined. The result is that the spot energy market that exists today cannot, on its own, provide the necessary price signal to induce sufficient (adequate) generation investment at least cost. Instead the regulator must intervene either by setting the spot price to induce the adequate generation or by imposing a resource adequacy requirement that provides revenues to induce adequate investment.

CAISO Spot Energy Market

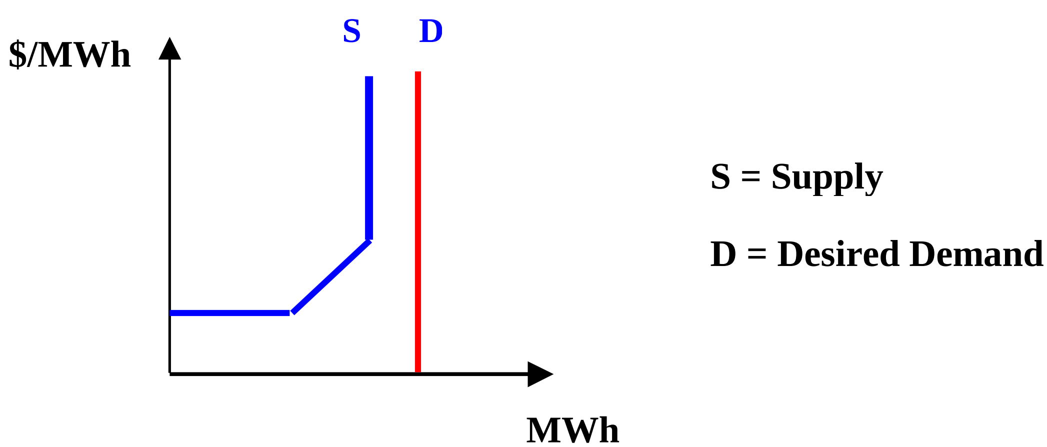

Figure 1

2. ISO inability to shut down service to specific customers creates a free rider problem.

Absent adequate investment in generation, a market experiencing shortage conditions should serve those consumers who pay for reliability (those who are fully resourced or willing to pay the highest spot market prices), and shut off those who have not paid for reliability. However, even if real-time meters were available to allow customers to respond to these price signals, because of the way electric grids are operated, it is difficult, if not impossible, for an ISO to shut down a specific customer in real time who chooses not to pay the system reliability costs. Because the ISO does not have this capability, there is little incentive for consumers to pay the higher prices required to support reliability. Instead,

[4] To prevent prices from escalating indefinitely, price caps must be imposed.

consumers have the incentive to "free ride" as much as possible. This free-riding problem will prevent a workable market for a reliability product from developing for too long to be useful in the present context.

B. Damaging side effects of structural problems are market power, investor risk, and a broken link between fixed cost recovery and the desired level of installed capacity.

These two structural problems with the demand side of the market – demand's inability to respond to price signals and the free rider problem – result in three significant side effects--market power, investor risk and a broken link between fixed cost recovery and the level of installed capacity:

1. Market power.

The inability of demand to respond to high prices increases suppliers' incentive to exercise market power. This in turn creates regulatory risk since investors know that market power pricing will be followed by efforts to mitigate prices. Regulatory risk is the fear that existing rules of the market will soon change. Regulatory risk translates into higher investment costs.

2. Investor risk.

The exercise of market power and the inability of demand to properly respond to price signals can lead to unstable energy spot market prices which fluctuate wildly. Even without market power, weather conditions, especially drought, can lead to huge year-to-year fluctuations in fixed-cost recovery. Over-reliance on this type of an energy spot market to send long-term investment signals results in a boom-bust investment cycle. This produces an unstable investment environment in which investors have long periods of losses punctuated by brief periods of extreme profitability. Such cycles may tend to raise the cost of investment by increasing the investor risk premium.

This investor risk problem is more severe in the West due to the region's significant dependence on hydro power, which is subject to a long-term drought cycle. Insulating fixed-cost recovery from weather fluctuations would partly solve the boom-bust cycle problem.

If investors are not efficiently insulated from spot market fluctuation and weather risk, California's ratepayers will pay exorbitant risk premia passed through the market from risk adverse investors.[5] Further, because the market-determined price applies equally to existing as well new capacity, any investor risk premium on new investment will also increase payments to existing capacity as well. If risk premiums are not lowered, California consumers can expect to pay more for their energy.

3. Broken link between fixed cost recovery and the desired level of installed capacity.

The third damaging impact of the structural problems is that there is no relationship between fixed-cost recovery and the desired level of installed capacity.

To attain generation adequacy in a market, investors must be induced to build adequate generation, and that requires a market that provides them with a sound reason for believing their fixed costs (as well as variable costs) will be recovered over the life of their investment when they do build that much capacity. Otherwise they will let the level of capacity sink below the adequate level until shortages send prices high enough that they believe they can recover their fixed costs, even in a capped market.

Without the market imperfections, the market would be expected to reach the optimal level of investment and to establish the average, and consequently long-run, cost to consumers of the capacity purchased. But even with the imperfections, the market can be described by a fixed-cost recovery curve that shows the relationship between the level of installed capacity and the average level of fixed cost recovery provided by the imperfect market.

[5] Risk is always costly and to be avoided when it is not the inevitable result of a useful price signal. Hence, we should insulate investors from weather risk (they cannot improve the weather) but expose them to performance risk, so they will improve their performance.

<u>Illustrative Fixed Cost Recovery (FCR) Curve</u>
(Existing Energy Markets)

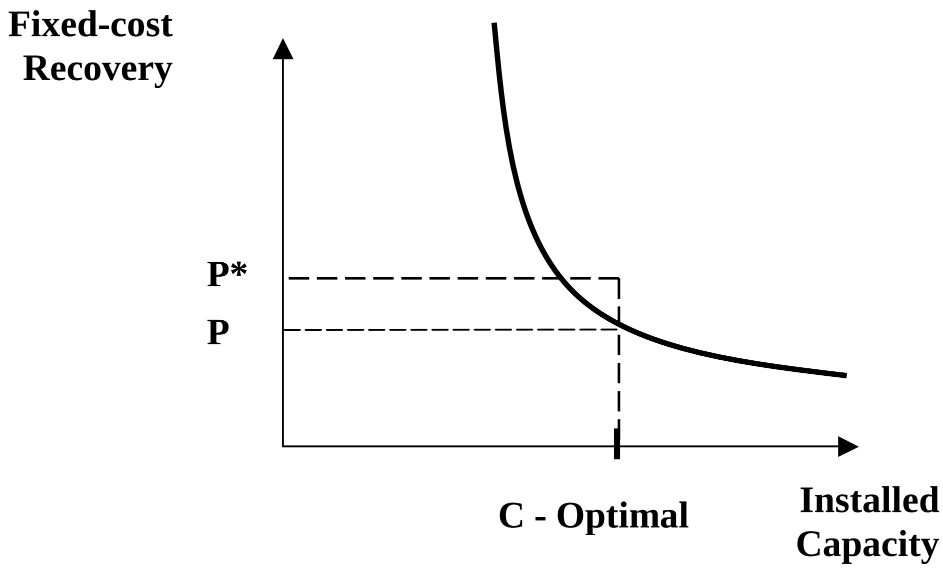

Figure 2

Figure 2 provides an illustrative Fixed-Cost Recovery (FCR) Curve in a capped energy market. The FCR Curve shows the level of fixed-cost recovery given the level of installed capacity. The FCR curve is established by first identifying the optimal level of installed generation capacity from the perspective of the consumer. This optimal level of installed capacity is shown as Capacity-Optimal or "C-Optimal". P is the fixed-cost recovery provided by the price-capped energy market. P* is the level of fixed-cost recovery 'necessary' to induce C-Optimal. For example, P* could be the annualized fixed-cost of a new peaker.

The Fixed-Cost Recovery (FCR) Curve in Figure 2 reflects two qualitative aspects of a price-capped energy market. First, because the energy market is subject to a low bid cap, fixed cost recovery, P, tends to be too low when capacity is optimal, that is, when there is adequate capacity for the desired level of reliability. Second, at a low-enough level of capacity, fixed-cost recovery will reach P*, which reflects a "normal" profit level for peakers. This will prevent the capacity level from falling without limit, and it reflects the low equilibrium level of capacity expected in such a market.

Because such a FCR Curve pays investors less than their fixed-costs when installed capacity is at the desired (optimal) level, it will not signal an adequate level of investment. This explains the broken link between fixed cost recovery and the desired level of installed capacity referred to in the introduction to this section. This can only be corrected by raising the FCR Curve so that it intersects the point corresponding to the optimal level of capacity and P*, the required fixed-cost recovery. (Please see explanation in Section IV.A and Section V.A.)

Without the two demand-side imperfections, the fixed cost recovery necessary to ensure supply adequacy can analytically be decomposed into two sources. (Please see Figure 3.) The first source of fixed cost recovery is the revenue above the supply (marginal cost) curve and below the market clearing price that would prevail under non-scarcity conditions-Pmc. (Pmc is equal to the marginal cost of the marginal generator-e.g., a peaking unit.) Figure 3 shows this as the area between the supply curve and the market-clearing price of Pmc. This area is labeled as Rents (R).

The second source of fixed-cost recovery is the scarcity rents earned during conditions of "scarcity". Figure 3 shows this as the difference between the peak price of Pp and the peaker marginal cost of Pmc times the quantity of transacted energy. This area is labeled as Scarcity Rents (SR).

Peak Pricing & Scarcity Rents

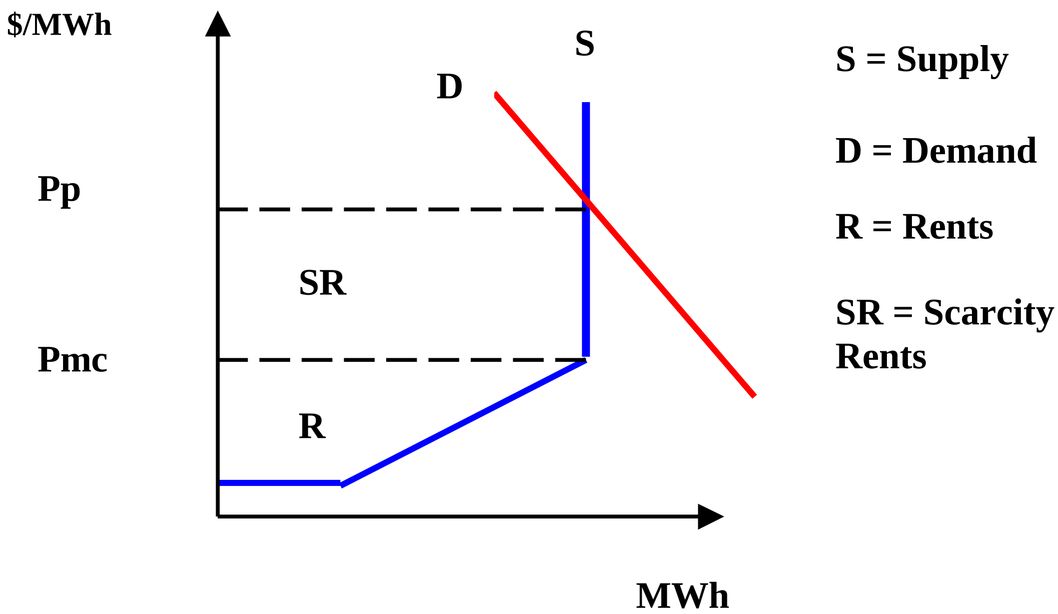

Figure 3

As Figure 3 shows, demand must be able to respond to prices so that the energy market alone can ensure the investor that there is a predictable link between fixed cost recovery and the level of installed capacity. Unfortunately, given the inelastic demand of today's markets (see Figure 1), prices cannot be properly determined by the market and require administrative intervention. Consequently, a major source of fixed-cost recovery for all generation must be adjusted by the regulator to ensure the proper level of investment to ensure reliability.

C. Market power pressures regulators to mitigate spot prices.

The consequence of the structural market problems described above and their impacts (e.g. higher potential for the exercise of market power and higher investor risks) is that they create regulatory pressure to cap the spot energy market. This then results in lower prices that tend to prevent the recovery of fixed costs of existing generation and therefore that do not encourage investment in new generation. This is because the regulator's price caps are set at levels below scarcity pricing. Without scarcity rents, the investor is not able to obtain the necessary fixed cost recovery of his generation investment particularly for peaking units that run for only a few hours each year. In other words, because of the spot energy bid caps, a significant amount of revenue is missing from the CAISO's spot energy market, just as it is from the Eastern ISO energy markets.

To induce adequate investment from the market, the missing revenues must be restored. But they must be restored carefully to avoid unintended incentives which would cause inefficiency and increase consumer costs.

D. Because the structural market imperfections and adverse impacts cannot be fixed within a reasonable time frame, the regulator must step in with Resource Adequacy (RA) programs to induce adequate investment in production capacity.

Eventually, energy markets are expected to develop sufficient demand responsiveness to balance supply and demand in real time. Eventually, it will also become possible to curtail individual customers on the basis of their energy contracts or requested reliability level. However, until these advance market structures are in place, markets cannot solve the reliability problem, and the task of inducing the adequate level of capacity for reliability will fall to the regulator. This is the fundamental reason for today's RA requirements, but there are other potential and important benefits created by RA requirements as well.

IV. HOW A WELL-DEFINED CAPACITY MARKET COMPENSATES FOR ENERGY MARKET IMPERFECTIONS

Since the energy market structural imperfections and related adverse impacts cannot be quickly solved, a capacity market-based RA program is needed to induce adequate investment in generation infrastructure. This capacity market-based RA program must induce the "right" amount of generation capacity in the right places—not too much, nor too little—at a just and reasonable cost to the consumers of California.

As stated in the introduction to this White Paper, "the primary purposes of the Commission's RA requirements are: (1) to ensure sufficient incentives for new electric infrastructure investment, and maintenance of necessary existing generation, by providing a revenue stream that is missing from today's capped energy markets to compensate generation owners for their fixed costs; (2) to ensure that this investment is provided in a way that minimizes total consumer cost of delivered power over the long run; and (3) to ensure that the induced investments are available when needed for reliability."

A well-designed capacity market complements the Commission's objectives to fully implement the Commission's RA policy in many different ways which are discussed in detail below:

A. A well-designed capacity market stabilizes and guides the market to provide the target level of generation adequacy at reasonable cost. It does this by drawing on the relationship between fixed-cost recovery and the desired level of installed capacity.

The first goal of a capacity market is to stabilize and guide existing markets to provide adequate capacity at a more reasonable cost and avoid crisis periods in the spot market. This guidance begins with an administrative determination of the adequate level of generation (based on reliability standards), but it can then rely on market mechanisms to determine the cost recovery of investment and the particular generation projects undertaken. This type of capacity market construct preserves market efficiency while circumventing the market imperfections discussed above.

To stabilize and guide existing markets to provide adequate capacity, a well-designed capacity market relies upon a fixed cost recovery curve which re-establishes the missing link between fixed-cost recovery and the desired level of installed capacity.
Figure 4 provides an illustrative administrative fixed-cost recovery curve.

The fixed-cost recovery curve in Figure 4 is established by first reaching an administrative determination of the adequate generation resource level. This is shown as Capacity Target or "C-Target"**.** C-Target is based upon reliability requirements and the decision-makers' determination regarding how much capacity is required to meet those requirements. A market mechanism is then relied upon to determine the average price of capacity. This is shown as Normal Fixed Costs or P' on Figure 4. The market will also determine the particular generation projects undertaken.

Illustrative Administrative Fixed Cost Recovery (FCR) Curve

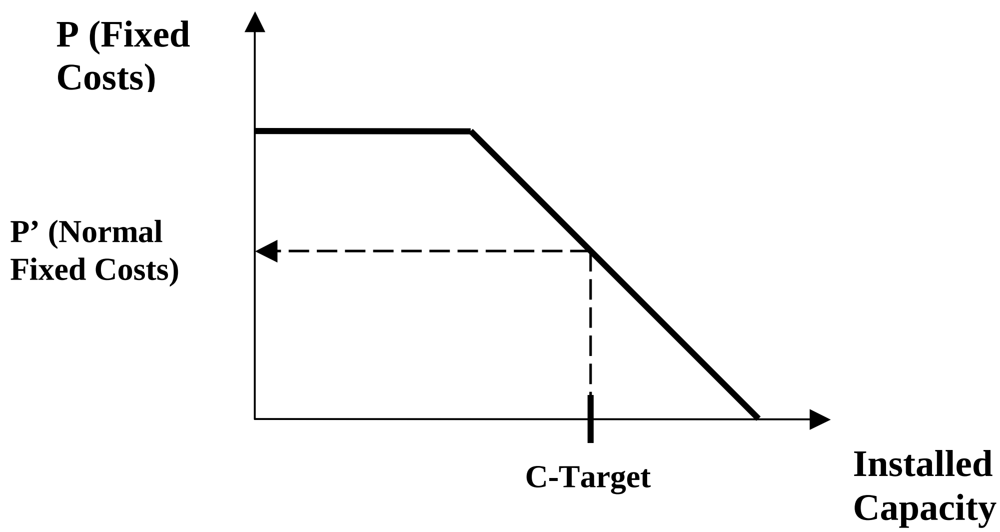

Figure 4

A well-designed fixed-cost recovery curve established for the capacity market will ensure that investors will be paid more than their fixed-costs when there is a shortage of generation, and less when there is a surplus. As such, investment would be stimulated when actual capacity is below C-Target (i.e., additional generation capacity is encouraged as long as the revenue for new entry stays above P', the fixed cost recovery point) and discouraged when actual capacity is above C-Target. In other words, if there was a surplus of capacity, and the price averaged less than P', investors would tend to stop investing and the average market price would rise. If the price averaged more than P' overinvestment would commence and the average market price would be driven down. Hence market forces and competition from new entry should then force the average capacity market price to oscillate around the level at which fixed costs are just recovered.

Further, the slope of the fixed-cost recovery curve should be set so there are no large differentials in fixed-cost payments between slight shortages and slight surpluses. In this way, a properly designed fixed-cost recovery curve will guide the market toward the target level of generation adequacy, C-Target, as administratively determined by reliability requirements. That is, the curve will guide the market to induce the "right" amount of generation capacity – not too much, nor too little – at price on average just high enough to pay for the fixed-cost of new resource capacity, while also avoiding great fluctuations in fixed-cost recovery and crisis periods in the spot market, both of which increase investor risk and costs to consumers.

B. A well-designed capacity market efficiently restores the revenues missing from the capped spot energy market.

As discussed in Section III, above, bid caps in energy markets prevent investors from recovering the full fixed-costs of their generation investments, resulting in what is often referred to as "missing revenues." To encourage adequate investment that will ensure the desired level of reliability, investors must be able to recover the fixed-costs on their generation investments. However, these payments to make up the "missing revenue" must be made in a manner that avoids creating unintended incentives that increase consumer costs.

By re-establishing and relying on a fixed-cost recovery curve to complement the existing energy market, a well-designed capacity market ensures that the necessary fixed costs and variable costs recovery dollars are present to induce a given level of installed capacity. As such, a well-designed capacity market makes up for the missing revenue.[6]

C. A well designed capacity market reduces both investor risk and market power.

A correctly designed capacity market reduces risk to investors and may almost eliminate market power in the energy market – both of which can result in significant savings to consumers.

[6] For instance, the NYISO's capacity market, which has undergone significant development, and is well understood, provides an internally consistent mechanism to restore the "missing revenues" necessary to encourage the generation adequacy necessary for reliability. It does this by adopting a downward sloping capacity-demand curve which is essentially a fixed-cost recovery curve.

Instead of mitigating energy market power, which can create significant market inefficiencies by distorting competitive behavior, a capacity market may have the ability to almost eliminate it by significantly eliminating the profitability of withholding in the spot market for energy.[7] For example, the current ISO-NE capacity market proposal reduces market power by subtracting the short-term profits of peakers (called PER, for peak energy rents) from the capacity demand curve. In this way any exercise of market power above the marginal cost of a combustion turbine costs a supplier as much in lost fixed-cost payments as it gains in the spot market—provided the supplier has sold capacity. If the potential for the exercise of market power increases investor risk, as described in Section III above, eliminating market power similarly reduces investor risk, thus lowering the expensive risk premia that consumers pay through higher energy bills.

D. A well-designed capacity market ensures against double-payment in the energy and capacity markets.

The ISO-NE market power mitigation proposal provides one method for ensuring against double-payment in the energy and capacity markets. It does this by subtracting the spot energy profits of peakers (PER) from the capacity payment established by the demand curve.

E. A well-designed capacity market ensures installed generation is available when it is needed.

Adequate installed capacity is necessary to ensure that enough capacity is available in real time. This is why adequacy of capacity has always been a primary goal of planners, and is today a primary goal of market design. However, in a market that relies on imports and exports, reaching the target level of internal capacity is not enough. This capacity must be made available when needed. A well-designed capacity market should ensure adequacy and also ensure availability of supply in the spot energy market by addressing the following: (1) market power; (2) competing markets with varying spot market designs, and (3) performance incentives.

[7] Although mitigation is often necessary, it is better to reduce or eliminate market power to the extent possible before mitigation is applied. Divestiture is the classic approach to reducing market power, and price caps are the classic approach to mitigating it. Capacity markets offer new possibilities that can reduce market power with less intervention than either of these approaches.

1. Market power.

A well-designed capacity market limits market power by promoting adequate capacity. Having adequate capacity is a pre-requisite for the control of market power. When capacity is short, there will be many hours in which there is very little spare capacity and in which many suppliers become pivotal. Such conditions are ripe for market power. Both for reliability purposes and to address market power, the first goal of the Commission's RA requirement, and for capacity markets as well, is to limit market power by avoiding capacity shortages.

A capacity market may limit energy market power by placing a must-bid requirement on all those who qualify for capacity-based RA payments. Such requirements are universal in Eastern markets, but their effect there is limited because suppliers may bid high and may export with impunity through virtual bids. Nonetheless a requirement to bid is useful in conjunction with other market power mitigation measures used in spot markets.

A third, and potentially more powerful, approach to reducing market power in the energy market is not a mitigation approach, but a method that seeks to eliminate a great deal of energy market power by taking away the desire to raise price. This approach subtracts peak energy rents from the capacity payment. As such, this approach eliminates a great deal of market power by taking away the incentive to raise the energy price without restricting bids.

Lastly, adoption of a sloped, rather than vertical, demand curve for a capacity-based RA product limits capacity market power. With a fixed reserve or fixed capacity target requirement, suppliers face a totally inelastic regulatory demand for their capacity product. As such, the potential to exercise capacity market power is heightened. On the other hand, with a sufficiently price elastic capacity demand curve, the potential to exercise capacity market power is greatly diminished.

2. Competing markets.

Besides market power, there is a second problem with making existing resources available when most needed—competition for both internal and external resources from other markets. Today approximately 20% of the CAISO's targeted adequate capacity must be secured from external sources. To assure performance of contracts from both internal and external sources, sanctions and penalties for non-performance must take into account legitimate opportunity costs in other markets.

Imposing such penalties on suppliers is likely to make the contract that imposes them more expensive and this expense is exactly the source of the fixed-cost-recovery revenue that is necessary to encourage investment in a market with capped spot prices. Consequently the need for costly penalties is determined by both resource adequacy and resource availability considerations. Without expensive penalties, and the fixed-cost payments to justify them, investment will not be induced and contracts with existing generation are less likely to perform when needed most.

However, the costliness of penalty-contracts means that LSEs will not voluntarily make use of them. To "save" money, LSEs will strongly prefer contracts without penalties or with escape clauses that render the nominal penalties ineffective. This tension between the need for meaningful penalties, but the reluctance to pay for them, reveals the central requirement of RA contract design. Either contracts must be standardized, easy to monitor, and include a meaningful penalty, or the LSE itself must be subject to a stiff penalty whenever its contracts fail to deliver, and delivery must be easy to monitor.

3. Performance incentives

The earliest capacity markets ignored performance and simply paid for nameplate capacity, or ICAP. Subsequently, the Eastern markets moved to measuring and paying for UCAP, or "unforced capacity". This is ICAP reduced by the percentage of time a specific unit is expected to be forced out of service. This is estimated from actual outage data provided by each generating unit. Although this is only a partial measure of performance and somewhat subject to gaming, it is nonetheless useful step in the right direction. Unfortunately, this measure does not capture the unit's performance at peak periods or a unit's ability to start quickly when needed, or the expense of keeping a unit available on short notice. As discussed below, ISO-NE has proposed an alternative performance measure intended to better capture such elements.

F. A well-designed capacity market provides an effective means for the Commission to monitor and enforce compliance with its RA requirements.

By providing a central transparent capacity market and standardized capacity product, a well-designed capacity market provides an effective means for the Commission and the CAISO to monitor and enforce compliance with the Commission's RA requirements.

G. A well-designed capacity market addresses free rider concerns associated with the implementation of retail choice.

Loads can take power in real time even without a contract, both because the ISO cannot monitor contract performance in real time and because the ISO does not have real-time control of power delivery to most loads. This implies that a load without adequate capacity contracts is no more likely to suffer a rolling blackout than a load that is adequately contracted. Consequently there is too little incentive to contract for adequate capacity when the system is short of capacity and such contracts become expensive. This is exactly when strong investment signals are needed. A capacity market replaces the absent signal to contract with an administrative requirement. Although this requirement cannot reflect individual preferences, it does address the systemic problem of collective underinvestment due to incentives that have been eliminated by the ability to free ride.

Because such a requirement imposes costs that could otherwise be avoided by free riding, loads will have an incentive to sidestep such requirements. Consequently, a well-designed capacity market will include effective monitoring and enforcement of its requirements.

H. A well-designed capacity market works closely with the CAISO's proposed locational spot energy market to ensure generation locates where it is needed, and not in areas that are inaccessible to load.

A locational capacity market (one that includes locational demand curves) can complement and reinforce the locational energy price signals to ensure generation locates where it is needed and not in areas that are inaccessible to load. In addition, a locational capacity market-based resource adequacy requirement addresses the investment and availability policy problems arising from the absence of locational energy pricing.

V. Potential Limitations of a Capacity Market—Fact or Fiction?

Common perceptions exist about what are the potential limitations of a capacity market. On a very preliminary basis, the following discussion explores what these notions are and whether or not they are valid.

A. Will a central spot capacity market interfere with bilateral trading?

Capacity market opponents commonly claim that a centralized spot capacity market will interfere with bilateral trading. However, an organized capacity market actually complements bilateral markets[8]. For example, in the Eastern markets, most capacity is traded bilaterally. The central markets provide a transparent spot price which facilitates efficient bilateral forward trading, and they provide a safe and accessible venue in which small LSEs can procure their requirements. However, the major advantage of a central market capacity market lies in contract enforcement. A centralized capacity market standardizes the capacity product and contract terms which are extremely simple by comparison with bilateral contracts. Hence monitoring is straightforward.

B. Do short-term capacity markets alone provide an adequate foundation for investment? Are they untested?

A common critique of short term capacity markets is that alone they do not provide a foundation for investment. This is almost certainly true under current conditions because neither short-term nor the medium term (3 to 6 year) markets can become effective until the market trusts that they are permanently in place. Ultimately, however, stable short term capacity markets may provide a foundation for merchant generation. Moreover, a central capacity market with a monthly spot auction, like those implemented in the New York

[8] Markets typically comprise two market types – forward contract markets and spot markets. Just as the New York Mercantile Exchanges's standardized futures contracts complement spot markets, bilateral contracts complement spot markets.

market, can assist in providing a foundation for investment by providing a spot market price around which market participants can contract bilaterally.[9]

PJM has proposed a longer term capacity markets with a forward (i.e. 3 to 4 year) obligation to encourage investment in new resources. At one point the three Eastern markets considered adopting a uniform long-term design, and had it studied by consultants with National Economic Research Associates (NERA). The resulting Capacity Resource Adequacy Model (CRAM) proposed capacity contracts that paid off in years four, five and six after the date of purchase in a centralized capacity auction. This proposal would have gone considerably further towards reducing an investor's risk than would the current PJM proposal for two-to-three year energy contracts, which cover almost none of the fixed costs of new investment because of planning and construction lags.[10] In principle, long-term capacity auctions might prove to be as effective as short-term capacity auctions, or even have advantages, but they are untested, need considerably more design effort and there mechanism is less transparent.

The real advantage of a long-term auction approach is that the auction price, if it limited to delivery more than three years in advance, will be subject to more market competition because new entrants can compete with existing generation. However, at this time, this advantage appears to be offset by additional design complexity and lack of experience with these markets. No such approach has yet been implemented.

---

[9] Since the California Energy Crisis in 2000-2001, generation developers have for the most part required longer term contracts in order to develop generation, but prior to that time there was a significant amount of merchant generation activity.

[10] Staff notes that the CRAM forward auction proposal, however, appears to be inconsistent with the CPUC's Resource Adequacy policy. The Commission has adopted an LSE specific resource adequacy obligation whereby each LSE is independently responsible to demonstrate compliance with the Commission's year-ahead and month-ahead forward Resource Adequacy requirement. However, under the CRAM proposal, the ISO, rather than LSEs, makes a forward (e.g., three year-ahead) financial commitment on behalf of the total load.

C. Since a capacity market approach relies partially on a regulatory scheme, should it be considered a pure administrative mechanism?

A common complaint regarding capacity markets is that the capacity price is determined by regulators, so it is not a market mechanism. This is based on a fundamental misunderstanding of markets in general and capacity markets in particular.

A capacity market is half regulatory mechanism and half market mechanism. The regulator determines the target level and ultimately the amount of capacity built. Through the auction process, the market determines the average price paid for capacity and consequently the long-run cost to consumers of the capacity purchased.

In a monthly auction, the price paid for capacity will be set by the interplay of the regulator's demand curve and the inelastic supply of capacity. But the market should tend to adjust that capacity supply level toward the regulator's capacity supply target (C-target) so that the capacity price is on average just high enough to pay the fixed cost of a new peaker. If that price averages less than fixed costs, investors would tend to stop investing, causing the average auction price to rise. If the price averages more than fixed costs, investors will begin to over-invest and the average auction price will be driven down. Hence market forces and competition from new entry should tend to force the average capacity market price to oscillate around the level at which fixed costs are just recovered.

The market, and not the regulator, will determine the average price paid for capacity. To the extent the regulator has anticipated this market price and designed the demand curve to have this height at the desired quantity of capacity (C-target), the market should tend to guide installed capacity to that target. In this way the regulator uses the market to achieve the desired capacity level. With good design, the regulator can control capacity, but the market will still control price. (See Figure 4.)

D. Do California's unique characteristics preclude it from being a suitable candidate for a capacity market approach?

The final and most difficult consideration impinging on any capacity market design in the Western Region is the high level of interdependence of western markets, requiring significant imports and exports, coupled with a low level of market design coordination. This will require both further research and a design that considers the ramifications of high external prices when the West as a whole runs low on capacity.

For example, having induced the right level of capacity, it is important to assure that it is available during emergency conditions. Because of competition between Western power markets, this will be the time that it is most costly to assure its availability. Consequently, contracts for capacity must impose a meaningful penalty for failure to perform during critical times.

With or without coordination, California's RA program should include appropriate availability contracting with external capacity. External capacity contracts must be free as possible from external recall provisions and include meaningful penalties for failure to perform during emergencies.

VI. CAPACITY MARKET ALTERNATIVES—EXISTING AND EVOLVING DESIGNS

This section provides a review of capacity market approaches that have been implemented or that are evolving in the New York ISO (NYISO), the New England ISO (NE-ISO) and PJM. The discussion below draws more on the NYISO experience because New York has the most advanced capacity market design that has been approved by FERC. Both the PJM and ISO-NE proposals have taken NYISO's design a bit further, but PJM is just in the process of submitting its design, and the ISO-NE's design, though mostly approved by a FERC ALJ, has not been finally approved by FERC.

This section first provides a conceptual discussion of the administratively set demand curve, and then describes the initial and changing capacity market designs in New York, PJM and New England. Lastly, there is a section on lessons learned and related policy questions.

At this juncture, the CPUC also recognizes that other "market correction" mechanisms are being discussed such as the capacity call option approach.[11] However, an in depth

[11] Please see the following papers for a review of call option proposals:

A. Hung-po Chao, Shmuel Oren, Robert Wilson; *Electricity Market Transformation: A Risk Management Approach*, Electric Power Research Institute (November 2004).

discussion on capacity options is beyond the scope of this initial white paper. Consequently, the CPUC Energy Division primarily considered the experience of Eastern markets in making recommendations in Section VII.

A. The recent design innovation in capacity market design is the use of a demand curve with a non-vertical slope.

Previously, all three capacity markets discussed here were first established based upon a completely vertical demand curve, such as the one in Figure 1. This completely vertical demand curve has resulted in a number of problems, including large capacity price variations when there were only small variations from C-target. The recent design innovation in capacity market design, now in effect in NYISO, is the use of a demand curve with a non-vertical slope—also referred to as a "downward sloping" demand curve The downward sloping demand curve is designed to provide price stability, address market power concerns, and provide a more stable revenue stream for resources. In New York, for example, the New York Public Service Commission (NYPSC) proposed the parameters for the NYISO to implement an administratively determined downward sloping demand curve. As discussed above, this curve provides a revenue stream to resources for recovering fixed costs at a pre-determined price. This is illustrated further in Figure 5 on the following page:

B. Schmuel Oren., "Ensuring Generation Adequacy in Competitive Electricity Markets", Chapter 10 in: Electricity Deregulation: *Choices and Challenges*, Griffin, M. James and Steven L. Puller, editors, University of Chicago Press, (June 2005).

Illustrative Administrative Demand (& FCR) Curve

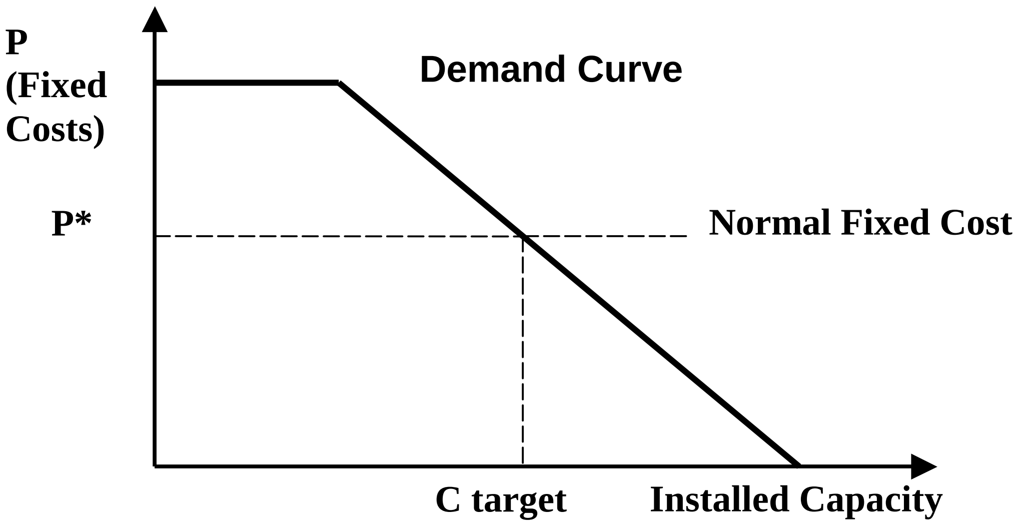

Figure 5

In Figure 5, fixed-cost recovery is shown on the vertical axis. The horizontal line represents the annual carrying costs of a new peaker generation unit. The quantity of installed capacity is shown on the horizontal axis. "C-target" represents the target level of capacity (e.g. 15-17% reserve margin, etc.), the minimum acceptable capacity level for reliability. The price of providing C-target is P*. P* could be the normal cost of new entry of a generator in the market, or the annualized fixed cost of a benchmark generator. The market would tend to provide the target capacity level because investment would be stimulated when actual capacity is below C-target (i.e., additional generation capacity is encouraged as long the revenue of new entry stays above P*, the fixed cost recovery point) and discouraged when actual capacity is above C-target. C-target should be set to ensure reliability and the demand curve should be set to ensure a revenue stream of P* (normal fixed-cost recovery) when installed capacity equals C-target. As discussed below, NYISO, in conjunction with the NYPSC, developed the downward sloping demand curve and it is operating in that market. Both PJM and ISO-NE are in the process of implementing administratively determined downward sloping demand curves.

B. The NYISO ensures adequacy for reliability through the implementation of its installed capacity (ICAP) market.

The NYISO ensures adequacy and reliability through the implementation of its installed capacity (ICAP) market. The NYISO's reliability goal is to ensure adequate installed capacity to achieve the New York State Reliability Council and Northeast Power Coordinating Council's target of a loss of load expectancy of no more than once in ten years standard.[12] This reliability standard is then translated to an installed reserve margin level by the New York State Reliability Council.[13] For the 2003-04 capability year, the installed capacity margin was 18% - a reliability requirement and target above the forecast peak load.

The reliability product which meets the ICAP requirement is known as an unforced capacity (UCAP) reliability product. Conceptually, the UCAP looks at a unit's forced outage rate and derates its installed capacity. [14] This approach provides some incentive to the ICAP supplier to keep its resource available.

Payments to ICAP suppliers are intended to induce generation investments. New York has three ICAP areas based on different capacity availability conditions within the NY ISO control area: Long Island, New York City, and the remainder of New York State. A demand curve is determined for each zone.

1. Early NYISO ICAP market design and lessons learned before the implementation of the capacity demand curve.

As discussed above, the NYISO market initially utilized a vertical demand curve. The initial result of the ICAP market was that prices were very high when capacity was even slightly below the target quantity, or prices went to zero when there was a capacity surplus.

---

[12] Loss of Load Expectancy or LOLE is the probability of disconnecting firm load due to resource deficiency of no more than once in ten years. Please see Northeast Power Coordinating Council "Document A-2: Basic Criteria for Design and Operation of Interconnected Power Systems", (Aug. 9, 1995).

[13] The CPUC understands that the ICAP working group is part of the New York State Reliability Council.

[14] More specifically, the UCAP measures the quantity of installed capacity which will be used to meet the ICAP requirement. The quantity of UCAP is based on the resources historic availability and the installed capacity of the unit. In essence UCAP = ICAP * Availability. The specific formula is contained in the NYISO Installed Capacity Manual.

Thus, the results were extremely volatile; the capacity price was either extremely high or low. Given the "boom and bust" market pricing signal, developers were reluctant to finance new projects. Consequently, the NYISO was concerned that new generation additions would not keep pace with growth in electricity demand within the state and that there would be capacity deficiencies. The NYPSC along with the NYISO proposed the downward sloping demand curve design to replace the "boom and bust" problems created by the vertical demand curve. They intended that the downward sloped demand curve determine both the amount of ICAP requirement as well as the fixed cost recovery for ICAP resources.

2. NYISO capacity demand curve

On May 20, 2003 the FERC approved the NYISO's demand curve filing (Demand Curve Order)[15]. NYISO's downward sloping demand curve design is based on the estimated cost of a new peaker and the curve is set by the price of installed capacity, which is determined at different reserve points. The price falls for increments above the target (118 % of peak load) until it is priced at zero at 132% of peak load,[16] and the curve goes to zero at different points in each of the three ICAP regions in the state. The demand curve will be phased in over three years and was established by a process involving the NYISO, NYPSC and stakeholders.

3. How does the demand curve model work?

The downward sloping demand curve construct replaces LSE bids in the previous auction design. The downward sloping demand curve approach accounts for bilateral contracts and self-supply. Suppliers of ICAP resources bid into the ICAP market. Also LSEs that have lined up ICAP resources offer their resources into the auction. Based on this information, the NYISO develops an aggregate supply curve. The ICAP requirement and price would be established where the aggregate supply curve crosses the demand curve. This is illustrated in Figure 6 on the following page. Different downward sloping demand curves

---

[15] 103, FERC 61, 201 (May 20, 2003), (NYISO Demand Curve Order).

[16] NYISO Demand Curve Order, page 3.

are established for each of the three different NYISO ICAP regions, to reflect different costs in different zones.

Proposed NYISO ICAP Demand Curve (Illustrative)

(Based on NYPSC Graphic; Statewide Parameters)[17]

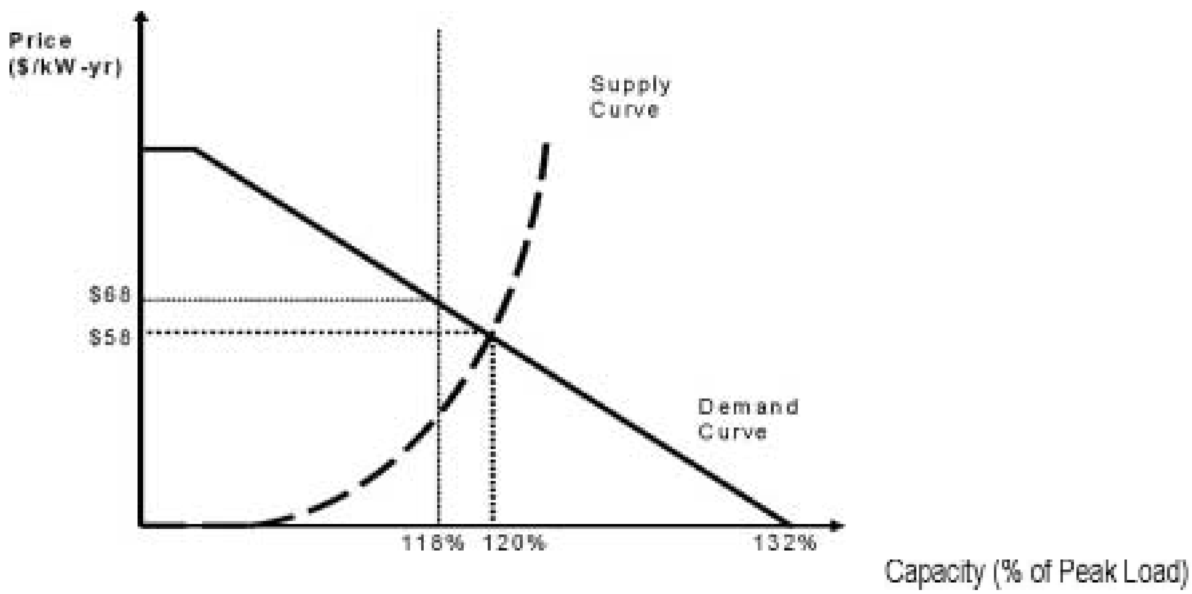

Figure 6

It is usual for the clearing point to be higher or lower than 118%. All ICAP resources accepted in the market are paid the ICAP market clearing price. All LSEs would pay the applicable market clearing price for their requirement. The ICAP price essentially becomes the "deficiency charge," in other words, the penalty for failing to procure capacity in the bilateral market.

The key component of the demand curve is the reference point of 118%. The reference point represents installed capacity when the reserve requirement is completely met. At that point the demand curve pays enough to cover the fixed costs of a new peaker when

---

[17] *2004 State of the Market Report New York ISO*, IV.B. Capacity Markets Results 2004, Potomac Economics, LTD, page 61, (July 2005).

expected peak energy rents are included. In New York the 100% of the reserve requirements is met when available capacity reaches 118% of peak load. The corresponding capacity value is set at a point that is equal to the fixed costs associated with installing and operating a new peaking combustion turbine. In the above Figure 6 that cost is set at $68/kW-year. Another important component of the demand curve is the point where the demand curve intersects the capacity axis, i.e., at 132% in the above Figure 6 when the capacity value drops to zero. The 132% point determines where exactly the demand curve should intersect the capacity axis. Together the 118% and the 132% points determine the slope of the demand curve.

4. How has the demand curve model worked so far?

Although it is early in implementation, NYISO reports to FERC show that the ICAP price and the revenue streams for suppliers have stabilized. A critical attractive feature of the New York downward sloping demand curve approach is that it is designed to substantially reduce market power in the capacity market. The administratively set downward sloping demand curve is established and results in a reasonable price for capacity. In the pre-capacity demand curve approach, even a slight shortage of capacity could result in prices near the cap, providing incentives for physical withholding. Under the downward demand curve approach, small changes in the quantity of capacity result in much smaller changes in the price, reducing the reward for withholding. Although the New York capacity market has had good reviews for stabilizing price and revenue streams some have expressed concerns with the New York demand curve. These concerns range from claims of exercise of market power in constrained zones to complaints that penalties against non-performing suppliers are not strong enough.[18]

---

[18] Peter Cramton and Steven Stoft, *A Capacity Market that Makes Sense*, 10th Annual Power Research Conference of the University of California Energy Institute, (March 2005).

C. Much like New York, PJM started its reliability product/market by implementing an installed capacity market (ICAP) process that was based on the old reserve sharing agreements from pooling arrangements.

Much like New York, PJM started its reliability product/market by implementing an installed capacity market (ICAP) process that was based on the old reserve sharing agreements from pooling arrangements. PJM then took into account resource availability by developing the UCAP approach product. The key overall features of the PJM model are similar to the NYISO's initial ICAP model. However, PJM has a daily requirement and conducts daily, monthly and multi-month capacity auctions and PJM requires 15% reserve margin. Also, initially PJM had one zone.

1. Early PJM capacity market and lessons learned

PJM has faced several concerns over the life of its ICAP market. First, because it had a daily requirement with a penalty for non-compliance based on an annual average cost of new capacity, it found that some capacity would "de-list" for short times in the summer in order to export energy and/or capacity during heat waves in the Midwest. This was remedied with an annual penalty. Suppliers must provide capacity for a certain period to receive ICAP payments.

The second problem was a period of market power in which one supplier with a large share of capacity raised the price from near zero to the maximum for a few months. This experience also provides some of the motivation for the current move to a sloped demand curve.

The third problem, which is the main driver behind the PJM's currently proposed reforms, is the need for a locational capacity requirement. PJM's current market is system-wide market and that has consequently failed to encourage generation construction in the more expensive-to-build-in eastern region of PJM, which faces a constraint on imports from the West.[19] This will be remedied with the new market, which is proposed to be zonal. There

[19] A PJM news release indicated that PJM has an adequate system wide reserve margin in that it has generation capacity available beyond the forecasted peak which provides a reserve margin of 26%; however, PJM is deficient in local areas (May 23, 2005). (Please see http://www.pjm.com/contributions/news-

had been some hope that PJM's "deliverability" requirement for new generation would prevent the need for a zonal capacity market, but this has not been the case.

The fourth problem faced by PJM is an inappropriate mix of new capacity. Investors have been building units that are insufficiently flexible. This makes load following difficult. The root of this problem may be the UCAP measure of availability which does not reward flexibility. In response to this, PJM has proposed to define a number of different types of capacity and set different prices for each.

PJM is seeking to address transmission constraints through a deliverability requirement and a move to a locational construct. New resources that want to qualify as capacity must pay for network upgrades to make their capacity count. Also, PJM is moving toward a longer-term planning horizon and believes that a stronger price signal must be provided to assure resources will be provided.

2. PJM's proposed capacity market design efforts and Reliability Pricing Model (RPM)

PJM presented its initial Reliability Pricing Model (RPM) design to stakeholders in 2004. The RPM model includes a four-year forward commitment for generation and demand. It also incorporates locational requirements. PJM envisions including an administrative demand curve similar to the NYISO downward sloping demand curve.

Although a downward slopping demand curve can better address the problem of generation retirements, the long-term market has the advantage of permitting proposed new generation projects to compete for capacity payments, thus allowing the short-run ICAP price to be controlled by the cost of new entry, and curbing market power. The long-term market would provide year-long contracts in the fourth year after the auction.

The new PJM approach has not been filed at FERC yet; but is likely to be filed this year. FERC recently held a technical conference (June 2005) on PJM's proposed RPM.[20]

---

releases/2005/20050523-summer-assessment.pdf)

[20] FERC Technical Conference to discuss capacity market construct used in the PJM Interconnection region, FERC Docket No. PL05-7-000 (June 16, 2005).

D. New England has an ICAP and UCAP design similar to the early designs discussed above in other eastern markets.

New England has an ICAP and UCAP design similar to the early designs in the NYISO and PJM markets discussed above.. The critical issue that New England is facing today is a lack of resources in key local areas. For example, there is a surplus of generation located in Maine; however, transmission constraints prohibit it from being fully deliverable to the other areas in New England outside of Maine. Furthermore, there are constrained areas in Connecticut where congestion prevents available supply from reaching load.

1. Early New England capacity market and lessons learned

The results to date in the ISO-NE suggest that capacity prices are low due to a system wide surplus and that the product definition is imperfect because it lacks a locational aspect. Also, the ISO-NE has seen a dramatic increase in the number of reliability agreements similar to RMR Agreements in California over the last year. At the FERC May 4, 2005 business meeting, Mr. Ethier from the ISO-NE stated,

> "Right now, we have about 2200 megawatts under 20 agreements, with another roughly 4600 megawatts actively seeking reliability agreements. That's about 20 percent of the pool, which is never how any of us intended this to sort of play out in New England. And that just, to me, points out the need for a long-term resource adequacy solution, because these agreements send no really useful incentives to existing units, or to potential new entrants to enter the market and resolve our problems. They're really just sort of a holding pattern." (p 116, May 4, 2005 FERC meeting transcripts.)

2. New England's Proposed Locational Installed Capacity Market (LICAP)

To address the issues outlined above, the ISO-NE is proposing a Locational Installed Capacity Market (LICAP). LICAP would include a locational requirement with separate demand curves developed for each designated region in New England. The LICAP mechanism, if it proceeds, will not be implemented earlier than October 1, 2006. The demand curves would be adjusted annually and reviewed every five years.

The LICAP approach is based on a downward-sloped demand curve similar to NYISO's, and has additional features unlike New York to eliminate market power, except for exports. The exercise of market power by exporting is subject to mitigation measures. The key additional feature of the LICAP design is the proposal to subtract peak energy rents from capacity payments. (NYISO also subtracts peak energy rents, but uses a forward looking estimate. Although this concept has been well accepted in NYISO, the values produced by the complex forward looking estimation process have been controversial.) The ISO-NE feature serves the same purpose as the NYISO feature, but it adjusts the ICAP payments so that total fixed-cost recovery is accurate.

As proposed in New England, this feature provides that when the spot market energy price exceeds the competitive energy price (based on the marginal cost of a new peaker), the difference between the competitive price and the market price is subtracted from the capacity payments made to all qualifying generation units that month. By this method, ISO-NE believes that it can eliminate the ability of even pivotal suppliers to profit from raising the spot energy price. A FERC ALJ initial decision approving the principal elements proposed by ISO-NE was issued on June 15. A final FERC decision is required before LICAP can be implemented.

E. Experience in Eastern markets results in lessons learned and related policy questions.

A capacity requirement/market may be appropriate to provide a partial stream of revenues in evolving energy markets. Some of the key lessons learned from the existing centralized capacity markets in NYISO, ISO-NE, and PJM are:

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 for California from the experiences from other states and ISO/RTOs include:

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 LSE's 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 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 other appropriate steps (e.g. subtraction of peak energy rents)?

VII. Energy Division Capacity Markets Recommendations

Based on the preceding discussion, this section makes recommendations regarding design issues that must be addressed in the development of an organized capacity market.

Staff notes that because reliability is the central purpose of any RA program, conceptually, the first step in any design process is to specify the reliability goal. However, the selection of the reliability target (e.g. 15-17% planning reserve margin) is separate from the design of the capacity market or other RA mechanisms intended to achieve that goal.[21]

[21] Note that New England chose to design their market to meet the engineer's reliability goal 83% of the time because that was the historical average and that average met the engineer's reliability goal on average (but not every year), and because markets never provide 100% certainty and any attempt to achieve this is likely to be exorbitantly expensive.

<u>Recommendation 1</u>: Adopt a short-run capacity market approach with a downward sloping capacity-demand curve for the CAISO.

California should take advantage of the lessons learned in the eastern markets by adopting a downward sloping demand curve.

<u>Recommendation 2</u>: 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.

Any capacity market approach must have some method of counting capacity that is tied to performance. As discussed above, the principal model in use today is UCAP. The Commission's Resource Adequacy work to date takes steps in this direction. ISO-NE has proposed an alternative mechanism that ties capacity payments to performance during low-reserve periods in an effort to provide greater reliability. The accounting mechanism should recognize variations in technology and prevent the substitution of resources that actually provide little reliability for ones that provide a great deal. For example a thermal resource that takes 24 hours to start may provide only half the reliability of a quick-start unit.

<u>Recommendation 3</u>: Consider subtraction of peak energy rents from the capacity payment.

In the development of the capacity curve, consider controlling market power by subtracting actual peak energy rents from the demand curve when computing capacity payments, as ISO-NE has proposed. Fixed-cost recovery is made up of net revenues from all sources, including the energy market, the ancillary services market and any capacity market revenues. Consequently it is wrong to ignore revenues from other sources when designing a capacity market. Moreover, consumers are sensitive to this correction, and it can play an import role in reducing market power and risk in the energy market.

<u>Recommendation 4</u>: Adopt reasonable locational installed capacity requirements with locally varying demand curves.

Unless and until adequate transmission is constructed, load pockets in the CAISO territory are likely to require special consideration. We note, however, that reflecting locational capacity presents a series of design problems:

(1) Specification of zones. The ISO-NE experience suggests that zones smaller then 4,000 MW become difficult to manage because prices

are too sensitive to changes in installed capacity. Hence there is an interaction between the market design and the reality of transmission constraints.

(2) Specification of transmission limits on capacity flows.

(3) Specification of rights to capacity transmission, if any.

(4) Specification of zonal adequacy requirements. NYISO specifies a requirement for the entire state and two requirements for two sub-regions, while ISO-NE specifies requirements for each sub-region, and no requirement for the ISO as a whole.

(5) Specification of a price calculation method. Although NYISO and ISO-NE appear to use different approach, they actually use the same economics applied to different styles of specifying the zonal adequacy requirements.

Staff is aware that the CAISO's June 2005 Local Capacity Requirements study may raise additional issues. See http://www.caiso.com/docs/2005/06/28/2005062816522619093.pdf.

<u>Recommendation 5</u>: Consider protecting against capacity exports during times of tight supply through the use of capacity prices that fluctuate seasonally.

Capacity is worth more in August than in November. Moreover, unlike the NYISO, for instance, which is largely surrounded by other regional transmission organizations (RTOs), the CAISO is the only organized Western market. Because there will be competition between the Western markets for capacity, the capacity market may need to pay more for capacity in August to make sure California gets what it needs.

<u>Recommendation 6</u>: Investigate the dependability of capacity import contracts during times of high West-wide load.

In contrast to the eastern RTOs, imports play a significant role in California. If dependability of capacity imports appears problematic, it may be necessary to develop special requirements for capacity import contracts, such as higher penalties for default, and/or a different price-setting mechanism than that used for internal capacity contracts.

This part of the design requires a significant research effort with regard to the deliverability of external power during extremely tight supply conditions and emergency supply conditions. There is no point in securing contracts that are 98% effective if they fail during the 20 hours each year when they are needed most. Internal capacity can easily be secured during emergencies. But, by the same token, other venues may choose to secure their capacity during emergencies, and that that may prevent delivery to California.

<u>Recommendation 7</u>: Make the fixed-cost recovery curve explicit.

Fixed-cost recovery drives investment. If an approach does not explicitly calculate how fixed-cost recovery varies with the capacity level it is impossible to tell whether too much, too little, or the right amount of investment will be induced. It is also impossible to tell how risky fixed-cost recovery will be and how much of a risk premium will be passed through to consumers. A capacity market approach developed for California should specify its desired fixed-cost recovery curve – i.e. the relationship between the level of installed capacity and the fixed-cost recovery that an investor can expect – and should show that its design comes close to providing this level of fixed cost recovery to investors.

<u>Recommendation 8</u>: Strive for regulatory credibility.

In addition to the design considerations discussed above, regulatory credibility is crucial to successful implementation of Resource Adequacy. Although this admonition is vague, several considerations are pertinent and helpful. First, experimental designs will almost certainly need to be adjusted, with each adjustment process an opportunity for changes in the level of fixed-cost recovery. Consequently, it is best to start with well established designs and make modifications cautiously. Second, the market should be well defended against the exercise of market power. Investors are not likely to take seriously any market that appears likely to become mired in market-power disputes. Third, high price spikes should be avoided as these also trigger calls for re-design of the market. Fourth, low capacity conditions, even if they are accompanied by good weather conditions and so cause no actual disruption, can trigger market intervention due to reliability requirements. Market intervention generally takes the form of regulatory procurement of capacity. The fear of such interventions can destroy regulatory credibility. Design the market to avoid low-capacity violations of reliability requirements.

VIII. Interagency Implementation

A. The Commission and CAISO have a key role in policy development and implementation.

As referred to in Section I, the Commission has made major policy determinations pertaining to resource adequacy in California. The Commission initially developed policy in its resource adequacy proceeding to provide "a framework to ensure resource adequacy by laying a foundation for required infrastructure development and assuring that capacity is available when and where it is needed." [22] In the February ACR"[23] the President of the Commission enlisted Staff to further develop policy by evaluating the prospect of moving forward with a capacity market approach to enhance the resource adequacy program currently under development in the Commission's Resource Adequacy proceeding. Staff was enlisted to look at regional alternatives pertaining to a capacity market and to also to consider alternative approaches for defining state and federal jurisdictional roles and responsibilities. In addition to policy development, the Commission has addressed implementation issues by conducting 19 workshops dealing with various issues pertaining to RA requirements which go into effect in June 2006.

The Commission and the CAISO have worked closely together to implement the RA requirements. For instance, the CAISO has developed the deliverability and local procurement requirements established by the Commission as well as parameters required in RA enforcement and compliance.

B. The Commission and CAISO should continue to collaborate.

If the preceding discussion is used as a framework, the Commission should adopt a policy to move to a capacity market and set the broad state policy in this regard. In addition, the Commission should set the reliability target that the capacity market is intended to meet. Once the state has formulated its policy, Commission and CAISO staff should work collaboratively to develop a market design proposal which will ultimately be submitted for FERC approval. This approach is consistent with the one used in New York to develop their

---

[22] D.04-01-050, page 11

[23] Rulemaking 04-04-003, page 1.

capacity market design. The New York Public Service Commission (NYPSC) first introduced the demand curve concept on May 21, 2002. The ICAP Working Group then had numerous meetings and spent considerable time working on the demand curve concept.[24] Similarly, there were many entities working "behind the scenes" on specialized issues such as the cost of entry for new generators. The NYISO finally filed a proposal with FERC for approval and implementation. The NYPSC supported the NYISO proposal at FERC. The NYPSC, NYISO, and Northeast Power Coordinating Council worked closely together to establish the ICAP requirement consistent with New York State Reliability Council (Reliability Council)[25] criteria and standards.

In approving the NYISO proposal, FERC stated the following:

> The NYPSC is, among other things, charged with ensuring that residents of the state have access to reliable utility service. The ICAP Demand Curve was initially proposed by the NYPSC in May 2002 and reflects a year of negotiations and discussions among the NYPSC, participants, and NYISO. The Commission considers the NYPSC's role in developing the ICAP proposal to be an important factor in our ruling. The NYPSC and NYISO have determined that the ICAP Demand Curve proposal will adequately and reliably serve customers' needs over the short and long term. The Commission also believes that these entities are better placed to establish the appropriate ICAP quantity New York requires to serve those customers over the short and long term. Finally, they have had nearly a year to craft this proposal with the benefit of participant input.

C. The extent to which the Commission should establish capacity market elements remains an open question.

The extent to which the Commission should establish capacity market elements remains an open question. For example, the Commission, rather than the CAISO, could develop the demand curve parameters and, once adopted, then the CAISO would incorporate

---

[24] *NYISO Proposal for Implementing a Demand Curve Spot Auction in the NYCA Installed Market Capacity*, NYISO Business Issues Committee (December 13, 2002).

[25] In New York, the Reliability Council conducts state reliability studies and sets the state's installed reserve margin FERC's NYISO Demand Curve Order (May 20, 2003).

them into the rest of capacity market design and be responsible for implementation. Among parameters that it may be appropriate for the CPUC to develop are:

1. Identify a reliability criterion such as a 1-day in 10-years loss of load expectation and translate this to a reserve margin objective;
2. Choose a maximum capacity for pricing that represents the maximum price one is willing to pay, even when short;
3. Choose the maximum capacity (i.e. zero crossing point)
4. Examine the historic variability (standard deviation) of capacity;
5. Calculate a Capacity Target for the specific market;
6. Calculate/estimate the cost of capital for the lowest-cost capacity; and
7. Draw the demand curve based on varying sets of assumptions stated above

This process would also resolve issues such as whether or not energy revenues are subtracted from the curve based on forecasts or after the fact reviews, and how that process will be conducted, how to determine the appropriate pricing point on the curve despite different inputs (e.g. bid in or physical generation within the area), how to reconcile "seams" issues such as imports and exports and purchases outside of California, and how to determine appropriate penalties for not meeting performance targets.

Keeping in mind overall RA requirements, staff seeks comment on the respective roles to be allocated to the Commission and the CAISO in capacity market development. In evaluating whether or not the Commission or CAISO should take the lead on a particular element, stakeholders should consider the following: 1) expertise; 2) expeditious implementation; 3) efficient use of resources; 4) effective implementation of capacity markets and revenue adequacy; and 5) process considerations.

Parties are encouraged to comment on various roles and responsibilities related to various stages of conceptualization, design, and implementation.

IX. Next Steps and Invitation for Comment

This is a Staff White Paper. It is not intended to represent the views of Commissioners, but rather to inform those views. The White Paper is the first step in responding to President Peevey's February ACR which directed staff to "evaluate how best to pursue an approach to capacity market development," by first developing a paper for review.

This paper presents staff's initial assessments and recommendations. In order for staff to more fully inform the Commission, and to move the process forward, staff seeks comment from interested entities. Comments may address any issue discussed in the paper, but should focus on:

(1) "Lessons Learned and Related Policy Questions" outlined in Section VI.E;

(2) Staff's recommendations outlined in Section VII above;

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

(4) Any other significant issues that are not addressed.

Staff requests that any comments be submitted by September 23, 2005, and that any reply comments be submitted by October 10, 2005. Comments should be submitted in compliance with the procedure set forth in the Ruling providing Notice of Availability of this White Paper, dated August 25, 2005.

Upon receipt of comments, Staff will make further recommendations to the Commission, including a recommendation on an appropriate process for moving forward with the investigation of capacity markets (e.g., a Commission-initiated OIR, CAISO/FERC-initiated process, or another alternative).

X. Glossary of Terms and Abbreviated Terms/Acronyms

A. Glossary of Terms

Capacity Demand Curve: A curve relating the level of installed capacity to a rate of fixed-cost recovery. For low levels of fixed cost recovery, the curve is above the normal fixed costs of a peaker and for high levels is below. Modern capacity demand curves are downward sloping in the region of the regulatory target capacity level. In NYISO this curve determines fixed cost recovery from the capacity market alone, while in ISO-NE it determines total fixed-cost recovery from both markets.

Capacity Markets: Bilateral contract and organized markets that allow participants to purchase or sell capacity products which meet reliability requirements. In the organized market, participants purchase when they are short or sell capacity when they have an excess amount. There are several different names for the organized capacity markets, but they are all basically the same in that they are an organized market to purchase or sell reliability (adequacy) products and they provide a revenue stream for resources in ISO/RTOs:

1. Installed capacity availability product (ICAP) – The "ICAP" market refers to the early capacity models that were implemented in the east coast.
2. "Demand Curve Model" – This refers to a capacity market which features an administratively downward sloping demand curve to stable price and revenues. The NYPSC along with the NYISO and its participants initially proposed the demand curve.
3. LICAP Model – The Local Installed Capacity Product is being proposed by the ISO-NE
4. RPM Model – The Reliability Pricing Model is being proposed by PJM.

Capacity Requirements: a minimum level of qualifying capacity that must be secured for resource adequacy requirements and made available to the system operator. In California, the CPUC has adopted a 15-17% level starting in 2006. Loads may procure capacity via bilateral contracts; self schedule their own resources; and/or participate in an organized capacity market.

ISO-NE and PJM explicitly recognized the capacity targets cannot be hit every year and consequently set their capacity target higher than their capacity requirement as determined by their reliability standard.

Installed Capacity: Capacity that qualifies for participation in the Commission's resource adequacy program. Generally, this is all operable capacity.

Reliability: The North American Electric Reliability Council (NERC) defines reliability as comprising: security, which describes the ability of the system to withstand disturbances (contingencies) and adequacy, which represents the ability of the system to meet the aggregate power and energy requirement of all consumers at all times.

Resource Adequacy Program: The basic purposes of a Resource Adequacy Program are to ensure the adequacy component of reliability of the electric system by procuring adequate generation resources as well as provide sufficient fixed cost recovery incentives for electric infrastructure investments within the states. It should also enhance security and reduce investor risk and market power to the extent this is efficient and does not interfere with the primary objective of adequacy.

B. Abbreviated Terms/Acronyms

(Partial List)

ACR-Assigned Commissioner Ruling

ALJ-Administrative Law Judge

CAISO-California Independent System Operator

CEC-California Energy Commission

CRAM-Capacity Resource Adequacy Model

ESP-Energy Service Provider

FCR-Fixed-Cost Recovery

FERC-Federal Energy Regulatory Commission

ICAP-Installed Capacity

ISO-Independent System Operator

LICAP-Locational Installed Capacity

ISO-NE-New England Independent System Operator

LSE- Load Serving Entity

NERC-North American Electric Reliability Council

NYPSC-New York Public Service Commission

NYISO-New York Independent System Operator

PER-Peak Energy Rents

PJM-Pennsylvania, New Jersey, and Maryland System Operator

PRM-Planning Reserve Margin

RA-Resource Adequacy

RAP- Resource Adequacy Program

RMR-Reliability Must Run

RPM-Reliability Pricing Model

RTO-Regional Transmission Organization

UCAP-Unforced Capacity