Potential Effectiveness of the Demand Curve Approach for Mitigation of Local Market Power in Capacity Markets

Eric Hildebrandt, Ph.D.
Department of Market Monitoring
California Independent System Operator

This paper was prepared for the Center for Research in Regulated Industries Advanced Workshop in Regulation and Competition, 21st Annual Western Conference, Monterey, California, June 19, 2009

Summary

One of the main issues currently being considered as part of the California Public Utility Commission (CPUC) Resource Adequacy (RA) proceedings is whether to establish a centralized forward capacity market, and, if so, how such a market should be designed.[1] Most forward capacity markets are designed to combat market power primarily by allowing sufficient time and financial incentives for entry of new supply resources. However, within many local areas, it may be insufficient or economically insufficient to rely on competition from potential new resources to mitigate the market power of existing suppliers. Consequently, most capacity market designs include some provisions aimed at mitigating local market power that exists within transmission constrained load pockets.

In California, the major proposals for centralized capacity markets incorporate two very distinct alternatives for the mitigation of local market power that may be exercised through economic withholding:

- A *demand curve* approach, based on New York ISO's capacity market design, has been proposed by Constellation[2] and Mirant;[3] and

- A *direct bid mitigation* approach, which includes specific structural, conduct and impact tests similar to those employed in capacity markets in New England and PJM, that has been proposed by a group known as the California Forward Capacity Market Advocates (CFCMA).[4]

The CAISO's assessment of these approaches is that the direct bid mitigation approach incorporated in the CFCMA proposal provides a significantly greater level of protection against local market power than an NYISO-style approach designed to mitigate local market power primarily through an administratively determined demand curve.[5]

---

[1] See, for instance, *Staff Recommendations on Capacity Market Structures: A Report on the August 2007 Workshop in Collaboration with the CAISO*, R.05-12-013, California Public Utilities Commission

[2] *Track 2 Proposal of Constellation Energy Commodities Group, Inc. Constellation New Energy, Inc. and Constellation Generation Group, LLC*, submitted March 30, 2007 in CPUC Rulemaking 05-12-013, included as Attachment B to *Comments of Constellation Energy Commodities Group, Inc. Constellation New Energy, Inc. and Constellation Generation Group, LLC on the CAISO's Capacity Market Evaluation Criteria Matrix*, August 3, 2007 (http://www.caiso.com/1c32/1c32bf5838de0.pdf) . ("Constellation proposal")

[3] *Track 2 Proposal of Mirant California, LLC, Mirant Delta, LLC and Mirant Potrero, LLC*, submitted March 30, 2007 in CPUC Rulemaking 05-12-013.(http://www.caiso.com/1c32/1c32bdc92b940.pdf)

[4] *Proposal for a California Forward Capacity Market*, August 3, 2007, submitted on behalf of California Forward Capacity Market Advocates (CFCMA) http://www.caiso.com/1c32/1c32ba981c0e0.pdf . CFCMA includes FPL energy,. NRG Energy, Reliant Energy, San Diego Gas& Electric and Southern California Edison. Although other proposals were submitted in the CPUC proceedings, these other proposals either did not call for establishment of a centralized capacity market or did not include sufficient specifics about how local market power would be mitigated to allow a meaningful assessment of this aspect of the proposal. ("CFCMA proposal"

[5] *Initial Comments on Capacity Market Proposals: Market Power Mitigation*, Department of Market Monitoring, September 14, 2007, http://www.caiso.com/1c59/1c59f04237820.pdf.

This paper reviews more recent experience with the demand curve approach in the NYISO, and provides a quantitative assessment of how this approach might be expected to perform given market conditions in the major load pockets of California (San Diego, the Los Angeles Basin and the San Francisco Bay Area). In addition, the paper reviews recent experience with the alternative direct bid mitigation approach in PJM and New England, and discusses how features of this approach more effectively mitigated local market power.

Results of this analysis indicate that given the concentration of ownership of existing generation sites in the major local pockets of California, significant additions of new capacity within constrained areas would be required to effectively mitigate local market power under a NYISO-style demand curve approach. In practice, significant barriers to entry for new supply are likely to exist in these areas due to various environmental and local permitting requirements and restrictions. Moreover, even if sufficient new supply could be added in these constrained areas, it is likely to be economically inefficient to rely on competition from potential new resources to mitigate the market power of existing suppliers, since this would require construction of significantly more capacity within constrained areas than would be required to actually maintain local reliability.[6] Thus, the paper concludes local market power within the CAISO major load pockets may be much more effectively mitigated under the major alternative capacity market proposals that incorporates more direct bid mitigation provisions such as those incorporated in capacity markets in New England and PJM.

I. NYISO-Style Demand Curve Approach

Demand Curve Approach

Capacity auctions that incorporate administratively determined demand curves are designed to provide three advantages compared to capacity auctions that are simply designed to procure a fixed target level capacity (or reserve margin):

- A downward sloping demand curve reduces price volatility by allowing capacity prices to change gradually over time in response to changes in the balance of supply and demand. This lower volatility can encourage greater investment and reduce costs of investment by reducing risk.

- A downward sloping demand curve can yield market results that better reflect the actual incremental value of any additional capacity procured in excess of the target level of capacity, or any incremental costs of any shortfalls of capacity procured below the target level of reserve capacity.

[6] In practice, recent studies by the CAISO suggest that within the major load pockets of the CAISO addition of new generation or transmission will be limited due to environmental and siting restrictions, and that that significant re-powering of existing generation will be necessary to simply replace aging generation and comply with potential New Restrictions on use of Once-Through-Cooling (OTC) in California (e.g. *Impacts on Electric System Reliability from Restrictions on Once-Through Cooling in California*, Preliminary CAISO Scenario Analyses, Updated Presentation, November 25, 2008, http://www.caiso.com/208b/208b8ac831b00.pdf In terms of local market power, this suggests that the very high level of concentration of ownership within these areas is likely to continue in the future.

- A sloping demand curve can mitigate market power by making it less profitable for existing suppliers with significant market share to physically or economically withhold capacity from the auction.

The NYISO-style demand curve approach that has been proposed in California is designed to mitigate market power almost exclusively by making it unprofitable for existing suppliers with significant market share to physically withhold capacity from the auction or economically withhold from the market by bidding in excess of actual going forward costs. In other words, the approach relies on the assumptions that while suppliers may increase the price by economically or physically withholding capacity, it will be unprofitable to do so due to the reduction in the supplier's capacity clearing the auction. Illustrative examples of the administrative demand curves used with this approach are provided in Section II of this paper.

A major concern with a NYISO-style demand curve approach is that within many local areas it may in fact be profitable for one or more suppliers to physically or economically withhold capacity from the auction if they are individually or jointly *pivotal* (i.e., that the residual supply of capacity from other suppliers is sufficient to clear the demand curve for capacity). As discussed later in this paper, this is a significant concern in the major local pockets of California, given the relatively high concentration of ownership of existing supply resources and the significant barriers to entry for new supply that are likely to exist in these areas due to various environmental and local permitting requirements and restrictions.

When significant local market power exists, an additional concern with the demand curve approach is that the quantity of capacity clearing the market may be significantly below the level of capacity actually needed to meet local reliability requirements. If this results from economic withholding of capacity, this would presumably force the CAISO to utilize its backstop procurement authority to contract with additional supply. Such supplemental procurement could have the perverse effect of further increasing the profitability of exercising local market power by providing a second opportunity for suppliers to earn capacity payments for any capacity that is economically withheld from the capacity auction.

Performance of Demand Curve Approach in New York

While specific parameters that would be used in the demand curve for California's market were not provided, the proposal by Constellation cites demand curves currently used by the New York ISO as examples of what demand curves might look like.[7] Recent experience in the NYISO's installed Capacity (ICAP) market suggests that while the demand curve approach may sufficiently mitigate market power on a system level, this approach does not effectively mitigate local market power within more transmission constrained urban areas.

As detailed in a 2006 NYISO filing, the NYISO's Independent Market Monitor has determined that despite the addition of a significant amount of new generation capacity in New York City, prices in the local capacity market for New York City have been uncompetitively high due to economic withholding of supply by one or more major suppliers.[8] Specifically, the ICAP prices

[7] See page 16 of Constellation proposal cited in Footnote 2.

[8] See New York Independent System Operator, *Tariff Revisions to Modify Installed Capacity Market, Mitigation Measures Applicable to Certain In-city Generating Units*, December 22, 2006.

for New York City continued to clear the maximum price of the demand curve of $105/kW/year. In order to more effectively mitigate the exercise of local market power, NYISO filed to establish conduct and impact tests for the Divested Generation Owners (DGOs) and apply a cap of $82/kW/year on bids that fail these tests.

On March 6, 2007, the Commission rejected the NYISO's filing, finding that among other things, the filing did not offer cost support for the proposed offer limits, and opened a proceeding pursuant to section 206 of the Federal Power Act to investigate the "justness and reasonableness" of the New York City ICAP market and how market rules need to be revised to provide a level of compensation that retains and attracts needed generation capacity, without either over-compensating or under-compensating generators.[9] Ultimately, the NYISO made a compliance filing in October 2007 that retains the basic structure of the NYISO's demand curve-based ICAP market, but refined the mitigation measures applicable to generators.

However, in a July 6, 2007 Order, FERC did take the step of referring the issue of whether any entity had engaged in manipulation of the New York City ICAP market to the Commission's Office of Enforcement (OE).[10] In an OE staff report issued in February 2008, FERC found that the high prices in the New York City capacity market were the result of economic withholding by the largest supplier within this market (KeySpan), which routinely offered all of its capacity at its bid cap.[11] However, the OE report found that this did not constitute manipulation for several reasons.

- First, the investigation found no evidence of any fraudulent or collusive behavior. As the FERC staff report explains, "market participants in the in-city ICAP market have always known that KeySpan, pursuant to the applicable market mitigation rules, was permitted to offer at its cap and set the market clearing price."[12]

- Second, FERC investigators noted that when it initially approved the NYISO's ICAP market design for New York City in 1998, the Commission explicitly contemplated that existing generation owners would offer capacity at their bid caps as long as it was profitable to do so. Specifically, the February 2008 report cited the Commission's 1998 prediction that:

> Given the circumstances [in New York City], existing suppliers are likely to bid the price cap and set the market clearing price at that level even as new generation is added and supply increases. This is because until the supply increases sufficiently to supplant substantial amounts of existing capacity, the existing suppliers will be assured that at least some of their capacity will be selected at any

(http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2006/12/NYISO_Tariff_filing_re_ICAP_Mitigation_Measures122206.pdf)

[9] *Order Rejecting Proposed Tariff Revision and Instituting Hearing and Settlement Judge* Procedures, March 6, 2007, ER07-360-000 and EL07-39-000.

[10] *Order Establishing Paper Hearing and Referring Certain Matters for Investigation,* July 6, 2007, ER07--39-000.

[11] *Findings of a Non-Public Investigation of Potential Market Manipulation by Suppliers in the New York City Capacity Market*, Enforcement Staff Report, Office of Enforcement, Division of Investigations, Federal Energy Regulatory Commission, IN08-2-000 & EL07-39-00, February 28, 2008. ("February 2008 FERC Staff Report")

[12] February 2008 FERC Staff Report, p. 17.

price so they have an incentive to bid the price cap to maximize revenues on those sales.[13]

- Finally, the FERC staff report indicated that KeySpan's bidding was economically rational profit maximizing behavior given that KeySpan knew they were pivotal in the capacity auction. As explained in the February 2008 FERC Staff Report, prior to the auction, KeySpan performed economic analysis of potential market outcomes under three strategies: (1) bidding all capacity at the cap, (2) bidding all capacity as a price taker, or (3) an intermediate strategy of bidding its capacity at "discounted" price below the applicable cap. However, based on this analysis, KeySpan determined that:

> … potential reward from clearing more capacity would be outweighed by the risk that some of its discounted capacity would remain unsold and the remainder of its capacity would clear at lower prices. While a discounting strategy had the potential to produce greater revenues, it also carried the risk of producing lower revenues because KeySpan could not predict or rely on how other [generation owners] would offer their capacity. In contrast, KeySpan's strategy of not offering at its bid cap maximized a relatively predictable revenue at a low level of risks….KeySpan adopted the less risky alternative of the three scenarios [i.e. the "offer at the cap strategy"].[14]

The experience in New York suggests that without direct mitigation of bids to mitigate local market power, the demand curve approach may be highly susceptible to the exercise of local market power in local pockets. In the case of KeySpan, for instance, it appears that it was profitable to bid its entire portfolio at the applicable bid cap even though its market share of the total available capacity in the New York City ICAP market was only about 20 percent – a level that is significantly lower than the portion of installed capacity controlled by individual entities within each of the major load pockets of California, as illustrated in the following section.

[13] 1998 Order, 84 FERC ¶ 61,287 at 62,357.

[14] February 2008 FERC Staff Report, p. 19.

II. Analysis of Demand Curve Approach in California

Overview of Methodology

This section provides a quantitative assessment of how a NYISO-style capacity market based on a demand curve approach might be expected to perform given market conditions in the major load pockets of California (San Diego, the Los Angeles Basin and the San Francisco Bay Area). The basic scenario used in this analysis is based on the following demand curve parameters:

- A net Cost of New Energy (CONE) of $92/kW year.[15]
- A maximum price cap equal to 1.58 times the value for net CONE ($145/kW).
- A slope or elasticity of the demand curve corresponding to a demand curve with an x-axis intercept (where price = $0) equal to 118% of the local capacity requirement.

The base scenario assumes that the net going forward fixed costs (GFFC) of the existing generation of the largest supplier is zero, reflecting an assumption that net annual operating revenues from this capacity would equal or exceed their annual GFFC. However, sensitivity analysis is performed under the assumption of net GFFC for existing generation of $16/kW/year. It should be noted that, in the future, as existing generation nation must be repowered (or retire) due to aging plant and restrictions on Once-Through-Cooling (OTC), the GFFC of at least some portions of existing generation are likely be higher and reflect the costs of repowering and elimination of OTC technology.[16]

The potential effectiveness of demand curves reflecting these various parameters in mitigating local market power was assessed for three major load pockets in the CAISO system:

- San Diego
- Western Los Angeles Basin (Western LA Basin)
- San Francisco Bay Area (Bay Area)

For each of these local areas, the potential for local market power is examined based on the following information provided in CAISO's 2007 and 2008 *Local Capacity Technical Analysis* studies:

- Total capacity needed to meet local capacity requirements;

[15] This value corresponds to the net CONE for the New York ISO system. In practice, the NYISO develops different demand curves for each month based on these annual values. However, for simplicity, this analysis was based on an annual demand curve derived from annual net CONE. This approach also reflects Mirant's recommendation that the CAISO adopt a demand curve approach on an annual rather than monthly basis.

[16] e.g. see *Impacts on Electric System Reliability from Restrictions on Once-Through Cooling in California*, Preliminary CAISO Scenario Analyses, Updated Presentation, November 25, 2008, http://www.caiso.com/208b/208b8ac831b00.pdf .

- Total supply of capacity available to meet local capacity requirements (including the Qualified Capacity for each unit posted by the CAISO in conjunction with the *Local Capacity Technical Analysis*); and
- The portion of available supply owned or controlled by the one or two major suppliers within each area (based on the Qualified Capacity for each unit posted by the CAISO, combined with the known owner of each unit).

The potential for local market power is examined in based on two methods:

- The profitability of unilateral market power by suppliers who are individually pivotal; and
- A Cournot equilibrium model of potential duopolistic market outcomes in areas such as the Bay Area, where two major suppliers each own a relatively large share of the available supply.

San Diego Area

Unilateral market power exists when a single supplier can significantly raise the Market Clearing Price (MCP) by *physical withholding* (not bidding capacity), and/or *economic withholding* (bidding significantly in excess of actual costs so that capacity does not clear the market). Although a supplier may be able to increase the MCP through physical or economic withholding, the supplier may not have an incentive to withhold unless it is profitable to do so. The supplier must earn a higher profit by withholding a portion of its supply, and selling a lower quantity at a higher price. If it is profitable for a supplier to withhold, the supplier has both the ability and incentive to exercise market power.

In the context of a capacity market based on the demand curve approach, the potential for unilateral market power can be directly assessed by calculating the profit maximizing amount of capacity that a supplier would offer, given the following information:

- The administrative demand curve, and;
- The residual supply that may be offered by other suppliers.

Within the context of the type of year-ahead or month-ahead capacity auction proposed by Constellation and Mirant, both the demand curve and potential residual supply would be known with a very high level of certainty.[17] Thus, under these conditions, the potential for unilateral market power can be easily assessed using a simple spreadsheet model.

The current local capacity requirements and available supply within the San Diego area, as provided in the CAISO's 2008 *Local Capacity Technical Analysis*,[18] are summarized in Table 1. As shown in Table 1, the available supply of capacity in San Diego is approximately equal to the

[17] For example, while the residual supply that may be offered by other suppliers may not be known with complete certainty, the maximum residual supply that could be offered would presumably be known with virtually complete certainty in a year-ahead or month-ahead capacity auction, since all capacity bidding in the auction would have to be installed or very near completion.

[18] http://www.caiso.com/1bb5/1bb5ed3d46430.pdf

2008 local capacity requirement in this area. The largest supplier in the San Diego is NRG, which owns about 38% of the available supply.

Table 1. Local Capacity Requirements and Available Supply San Diego Area

San Diego Area Requirement	2,957 MW	
San Diego Area Supply		
NRG	1,133 MW	(38% of supply)
Dynegy	702 MW	(24% of supply)
SDG&E	777 MW	(26% of supply)
Other Suppliers	335 MW	(12% of supply)
Total Sub Area	2,959 MW (~100% of requirement)	

Figure 1 illustrates the unilateral market power of the largest supplier in San Diego (NRG) in terms of the residual demand curve that is assumed to face the supplier in this analysis, or the amount of the supplier's capacity that would clear the local capacity auction at various market clearing prices. This residual demand curve represents the overall demand curve for capacity in the San Diego area used in this study, less the portion of this demand that could be met by the residual supply controlled by all other suppliers within San Diego. As shown in Figure 1:

- The residual demand for capacity owned by the largest supplier is inelastic (at the price cap of $145/kW/year) for up to about 800 MW of the supplier's 1,113 MW of capacity.

- For sales above about 800 MW, the residual demand curve for the largest supplier's capacity slopes downward, reflecting the downward slope of the overall demand curve used in the capacity auction.

- If the largest supplier offered all of its capacity at or below the net cost of new entry ($92), all of the supplier's capacity would clear the auction, with the market clearing at net CONE of $92/kW/year.

Figure 2 shows the capacity market revenues earned by the largest suppliers for different levels of sales. As shown in Figure 2, the largest supplier maximizes capacity market revenues by making sales of about 830 MW, at which level the MCP for capacity would still clear at the price cap of $145/kW/year. As shown by the dotted lines in Figure 2, these results are not significantly affected by the assumption of the supplier's net going forward fixed costs (i.e., $0 or $16/kW/year).

Figure 3 depicts the profit maximizing level of sales by the largest supplier in terms of the overall demand curve and level of potential supply in the local capacity auction. As shown in Figure 3, under a scenario where the largest supplier maximizes profits by exercising unilateral market power, the volume of total capacity clearing the auction equals 2,650 MW, or only about 90% of local capacity requirement.

The basic approach illustrated in Figures 2 and 3 was also used to assess the potential impact of various levels of new supply on capacity market results. Results of this analysis, as summarized in Table 2, indicate that:

- The addition of about 600 MW of new supply (owned by entities other than the two existing largest suppliers in San Diego) would increase the overall level of capacity in San Diego to about 120% of the area's 2008 local capacity requirement.

- Under this scenario, the unilateral market power of the largest supplier would be reduced to the point where the profit maximizing level of supply sold by NRG would result in a MCP equal to 100% of the net CONE ($92/kW/year).

- The addition of only 300 MW of new supply would increase the overall level of capacity in San Diego to about 110% of the area's 2008 local capacity requirement, at which point the profit maximizing level of supply sold by NRG would result in a MCP equal to about 128% of net CONE ($118/kW/year).

- The addition of about 890 MW of new supply would increase the overall level of capacity in San Diego to about 130% of the area's 2008 local capacity requirement, at which point the profit maximizing level of supply sold by NRG would result in a MCP equal to about 73% of net CONE ($67/kW/year).

Figure 1. Residual Demand Curve Facing Largest Supplier - San Diego Area

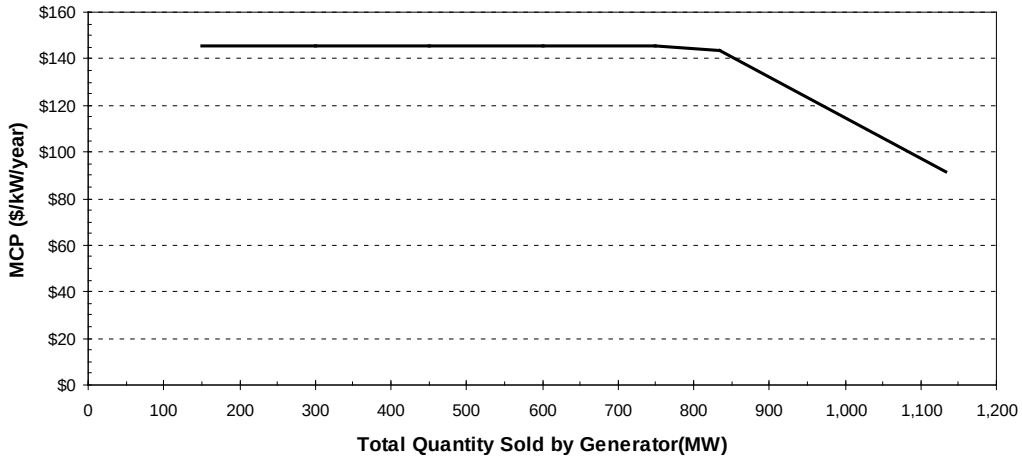


Figure 2. Profit Maximizing Level of Capacity Sales for Largest Supplier San Diego Area

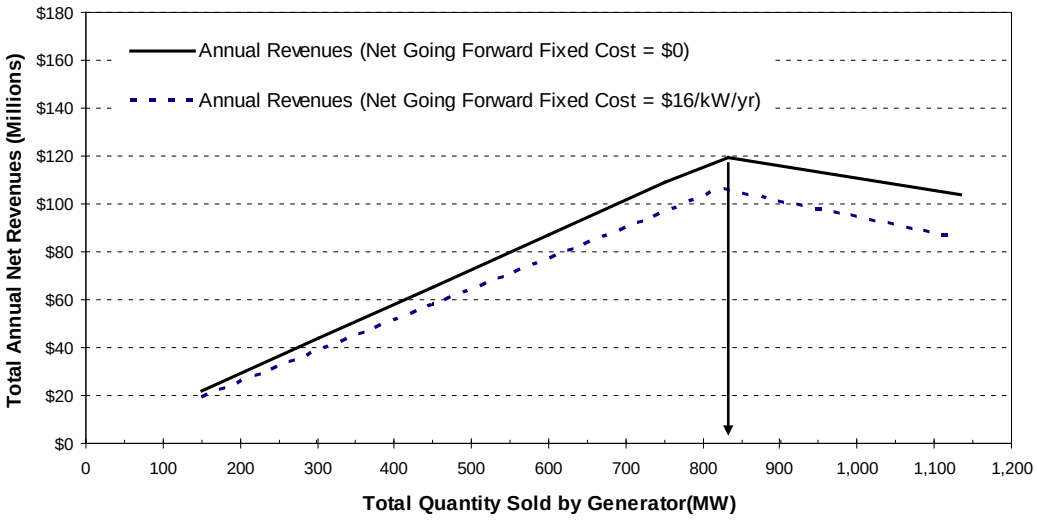


Figure 3. Potential Unilateral Market Power
San Diego Area

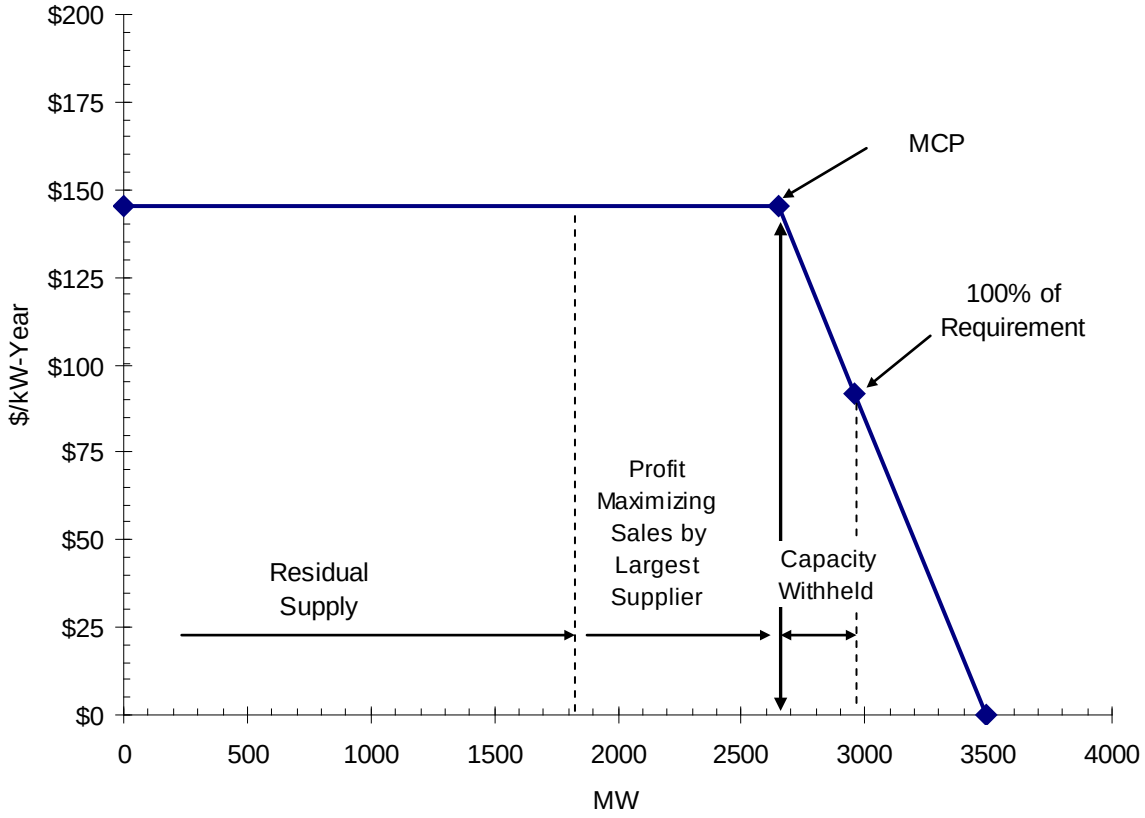


Table 2. Potential Impact of New Supply on Capacity Market Results
San Diego Area

				Capacity Market Outcomes		
Scenario	Scenario Assumption (New Supply)	Supply as % of LCA Requirement	Supply Owned by Largest Supplier	MCP ($/kW/yr)	MCP as % of Net CONE	MCQ (% of Req.)
2008 LCR Study	None	100%	38%	$143	156%	90%
1	300 MW	110%	35%	$118	128%	95%
2	**600 MW**	**120%**	**32%**	**$92**	**100%**	**100%**
3	890 MW	130%	29%	$67	73%	105%

Western LA Basin

The demand curve approach proposed by Constellation and Mirant – as well as the direct bid mitigation approach proposed by CFCMA – suggests that the local capacity auctions would be performed using the Local Capacity Areas (LCAs) defined by the CAISO. However, as noted in previous comments, DMM believes additional analysis of how specific capacity requirements may be established for some local areas is necessary, such as the Bay Area and Western LA Basin. Specifically, DMM notes that in these areas, it may be difficult to specify a fixed capacity requirement, due to the existence of various layers of reliability constraints and sub-area requirements. Incorporating these various sub-area constraints within LCAs into capacity market requirements will show that the degree of local market power is much greater than may be suggested based on the overall LCA supply margin and concentration of ownership reflected in aggregate LCA requirements and supply data.[19]

An example of this type of sub-area or constraint is the Western LA Basin. In the CAISO's 2007 *Local Capacity Technical Analysis,* this area was identified as a separate sub-area, for which a specific additional capacity requirement was established.[20] As shown below, one supplier owns 45% of the capacity within the sub-area, and is clearly pivotal in order to meet the capacity requirement for this sub-area.

Table 3. Local Capacity Requirements and Available Supply Western LA Basin Sub-Area

Sub-Area Area Requirement	3,788 MW (2007 LCA Study)
Sub-Area Supply	
Williams (Bear Stearns)	2,019 MW (45% of sub-area supply)
Other Suppliers	2,376 MW (55% of sub-area supply)
Total Sub Area	4,432 MW (117% of sub-area requirement)

Given these supply and demand conditions, the same approach that was illustrated in the previous section can be applied to assess the potential unilateral market power that would exist in the Western LA Basin under the demand curve approach to a local capacity market. Results of this analysis are shown in Figure 4 and Table 4. Table 4 also includes summary results for a

[19] If these additional layers or dimensions of local reliability requirements are ignored, auction results based on a fixed capacity requirement may be highly inefficient and/or require the CAISO to rely on backstop contracting ability to meet local reliability requirements. Thus, while ignoring these additional layers or dimensions of local reliability requirements might allow local capacity auctions to be run based on a relatively simple market design based on a single market clearing price, this would not solve this fundamental problem.

[20] *2007 Local Capacity Technical Analysis, April 21, 2006, page 59,* http://www.caiso.com/17e2/17e2851b23400.pdf In the *2008 Local Capacity Technical Analysis*, results identify three separate transmission constraints which may constitute the single largest contingency that would need to be met by local capacity. One of these – the Barre outage – appears to correspond closely with the sub-area requirements for the Western LA area provided in the 2006 LCA Study. Specifically, the effectiveness factors for the constraint provided in the study show that the bulk of the capacity that is effective to meet this contingency is owned by Williams. However, since results in this study did not include a specific requirement for the Western LA sub-area, analysis in this report is based on data presented in the 2007 study.

variety of scenarios which show the potential impact of additional new supply additions on capacity market results.

- As shown in Figure 4, the largest supplier would maximize revenues form the capacity market by selling just over 1,000 MW, or about half of the largest supplier's actual installed capacity.[21]
- At this level of sales, the capacity MCP clears at $138/kW/year, or 50% above the net CONE used to set the demand curve, as shown in the base case scenario in Table 4.
- The volume of total capacity clearing the auction equals about 3440 MW, or only about 91% of the local capacity requirement.

As shown in Table 4, the amount of supply within the Western LA Basin sub-area currently equals about 117% of the 2007 capacity requirement for this sub-area. However, due to the very large portion of existing supply owned by the largest supplier (45%), significant additional supply would be needed to ensure more competitive market outcomes.

- With the addition of about 680 MW of new supply, the unilateral market power of the largest supplier would be reduced to the point that the profit maximizing level of sales by the largest supplier would result in a capacity MCP equal to the net CONE used to set the demand curve ($92/kW/year).
- However, under this scenario, the total amount of supply within the Western LA Basin would need to be increased from 117% to 135% of the capacity requirements for the sub-area.

This further illustrates how it may be inefficient or insufficient to rely on competition from potential new resources to mitigate the market power of existing suppliers within areas of the CAISO grid such as the Western LA sub-area. In addition, within local areas such as this, significant barriers to entry may also exist that make it difficult for the market monitor to assess the actual cost of new entry to be used in the demand curve for local areas. For these reasons, DMM believes that any proposal should include additional provisions to explicitly mitigate local market power, and should avoid over-reliance on entry of new capacity in load pockets.

[21] These results are not significantly affected by the assumption of the supplier's net going forward fixed costs (i.e., $0 or $16/kW/year).

Figure 4. Potential Unilateral Market Power
Western LA Basin

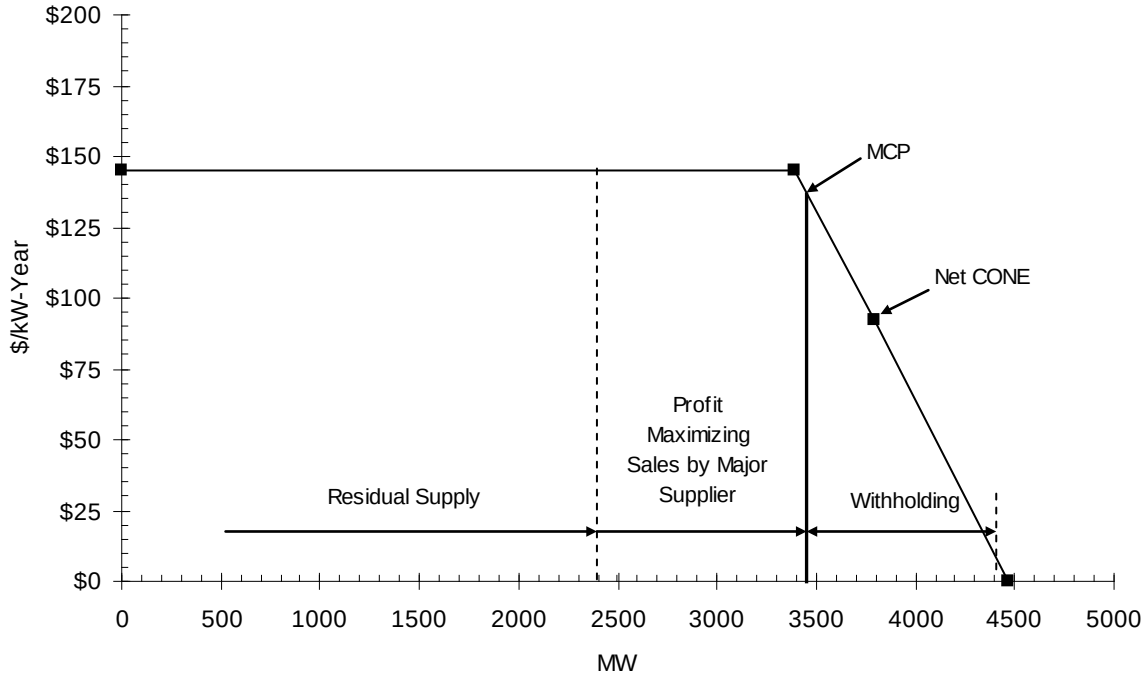


Table 4. Potential Impact of New Supply on Capacity Market Results
Western LA Basin

				Capacity Market Outcomes		
Scenario	Scenario Assumptions (New Supply)	Supply as % of LCA Requirement	Supply Owned by Largest Supplier	MCP ($/kW/yr)	MCP as % of Net CONE	MCQ (% of Req.)
2007 LCR	none	117%	45%	$138	150%	91%
1	300 MW	125%	42%	$118	128%	95%
2	500 MW	130%	41%	$104	114%	98%
3	**680 MW**	**135%**	**39%**	**$92**	**100%**	**100%**
4	870 MW	140%	38%	$79	86%	102%

Bay Area

Within the Bay Area, two suppliers each own a large portion of the supply available to meet local area capacity requirements, as reflected in the information in the CAISO's *2008 Local Capacity Technical Analysis* provided in Table 5.

Table 5. Local Capacity Requirements and Available Supply Bay Area

Bay Area Requirement	4,688 MW
Bay Area Supply	
Calpine	2,573 MW (41% of supply)
Mirant	2,347 MW (38% of supply)
PG&E	613 MW (10% of supply)
Other	681 MW (11% of supply)
Total	6,215 MW (132% of requirement)

Given the relatively large portion of capacity owned by the two largest suppliers within the Bay Area, the approach for assessing unilateral market power illustrated in previous sections of this report may significantly underestimate that actual local market power.[22] Under such market conditions there is a strong potential for duopolistic market power due to the very large combined market share controlled by the two largest suppliers (89%). Therefore, this section examines the potential for local market power in the Bay Area from the perspective of unilateral and duopolistic market power.

Figure 5 shows an assessment of the potential for unilateral market power given the current supply and demand conditions in the Bay Area. Results of this analysis indicate a much lower degree of local market power within the Bay Area than in other areas examined in this report:

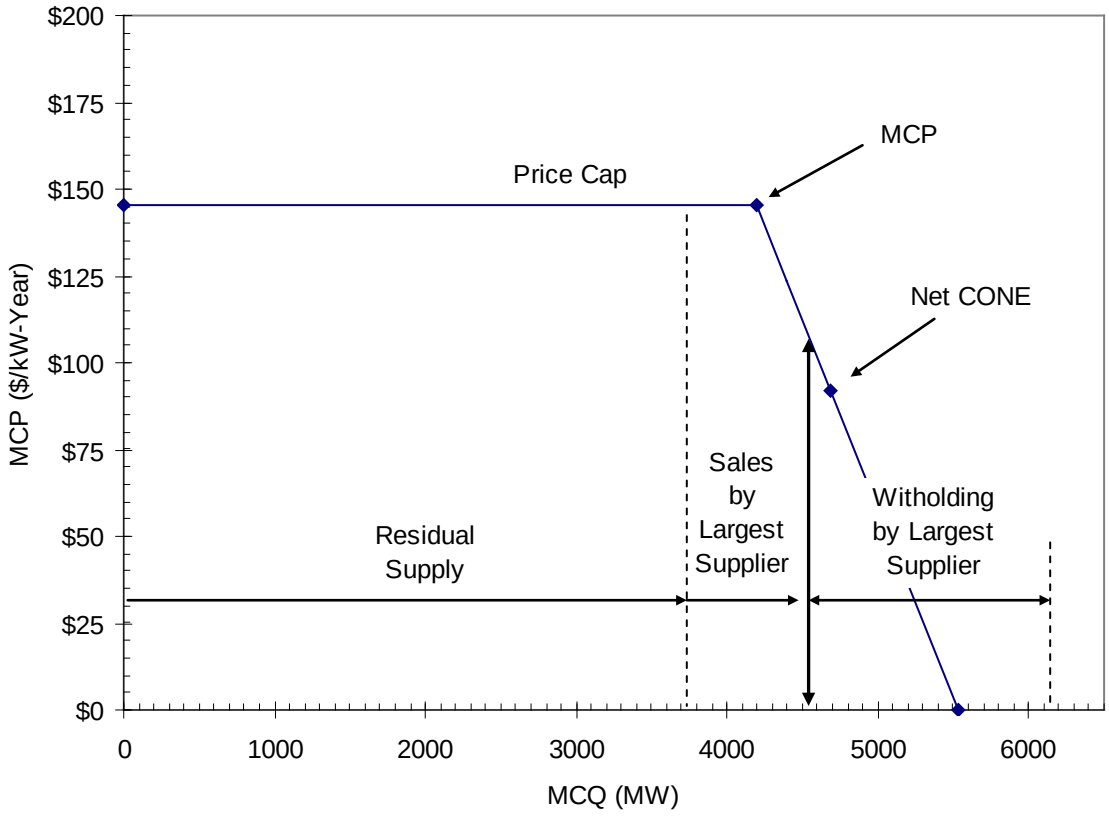
- The profit maximizing level of supply sold by the largest supplier equals about 820 MW, or about 35 percent of the largest supplier's actual installed capacity, for the base scenario.
- The MCP clears at an MCP of $106/kW, or about 15% above the net CONE used to set the demand curves.
- The MCQ equals about 97.4% of the local capacity requirement.

[22] In addition, as in the case of the Greater LA Basin, additional layers of reliability constraints exist within the Bay Area that would need to be factored into any local capacity auction in order to ensure that these reliability requirements are met. Examples of these various constraints or sub-area requirements are identified in the CAISO's *2008 Local Capacity Technical Analysis* and *2007 Local Capacity Technical Analysis.* Incorporating these various sub-area constraints within Local Capacity Areas into capacity market requirements will show that the degree of local market power is much greater than may be suggested based on the overall LCA supply margin and concentration of ownership reflected in aggregate LCA requirements and supply data.

- Under the assumption of net GFFC of $16/kW/year, the optimal level of withholding is slightly lower, with the largest supplier selling almost 900 MW, so that total capacity clearing the market equals about 99% of the requirement. Under this scenario, the MCP clears at $98/kW/year, or about 6% above the net CONE used to set the demand curves.

Further analysis of the potential for unilateral market power in the Bay Area under scenarios representing different levels of new supply is provided later in this section.

Figure 5. Profit Maximizing Level of Capacity Sales for Largest Supplier Bay Area



The potential for duopolistic market power can be assessed using a simple Cournot model of market behavior under duopolistic conditions. With this approach, the reaction function of each of the two major suppliers is calculated – representing the profit maximizing amount of capacity sold by each supplier given various levels of sales by the other major supplier.[23] The intersection of the suppliers' reaction functions represents the Cournot equilibrium – or optimal level of sales by each of the two suppliers. Figures 6 and 7 show results of this analysis for the two largest suppliers in the Bay Area.

[23] It is assumed that all other supply is bid as a price taker, so that the residual demand facing the two major suppliers is equal to the demand curve for local capacity less the residual supply of capacity of the other suppliers.

- As shown in Figure 6, the reaction functions of each supplier intersect at multiple points, reflecting multiple combinations of duopolistic equilibrium. Under each of these points, the two major suppliers each sell between 1,300 and 1,500 MW, with a total of 2,800 MW sold by the two suppliers combined.

- As shown in Figure 7, the optimal level of combined sales for the two major suppliers corresponds to the point at which the demand curve reaches the price cap of $145, which is set at 58% above the net CONE.[24]

- Under this scenario, total capacity clearing the auction would equal about 90% of the local area capacity requirement.

- Under the assumption of net GFFC of $16/kW/year, the overall net revenues earned by the two suppliers are reduced, but the overall market clearing prices and quantities remain the same.

Thus, although analysis might suggest that only a moderate level of unilateral market power may exist in a local capacity market based on a demand curve for the Bay Area, these results suggest that very high potential for uncompetitive market outcomes would exist due to the very large market share of the two largest suppliers in the Bay Area.

Figure 8 shows the impact of an additional 350 MW of new supply on the Cournot equilibrium for the two largest existing suppliers within the Bay Area. As shown in Figure 8:

- Under this scenario, the reaction functions intersect at a single point, indicating the existence of a unique Cournot equilibrium.

- Under these conditions, the two suppliers would maximize profits by each selling about 1,260 MW at an MCP of $138/kW/year.

Table 6 summarizes results of other scenarios showing the impact of various levels of new supply additions on the potential local market power within the Bay Area, using the unilateral and Cournot approaches for assessing market power previously described in this paper.

Figure 9 shows a comparison of results derived using the unilateral and Cournot approaches, in terms of how the MCP for capacity declines as the amount of supply increases (as a percentage of total capacity requirements).

[24] In fact, the existence of multiple equilibriums is attributable to the effect the price cap has on the reaction function of each supplier. Further analysis shows that if the price cap is removed (or raised), a single unique Cournot equilibrium would exist with each owner selling 1,379 MW at a price of $150.

Figure 6. Reaction Functions of Two Largest Suppliers
Bay Area

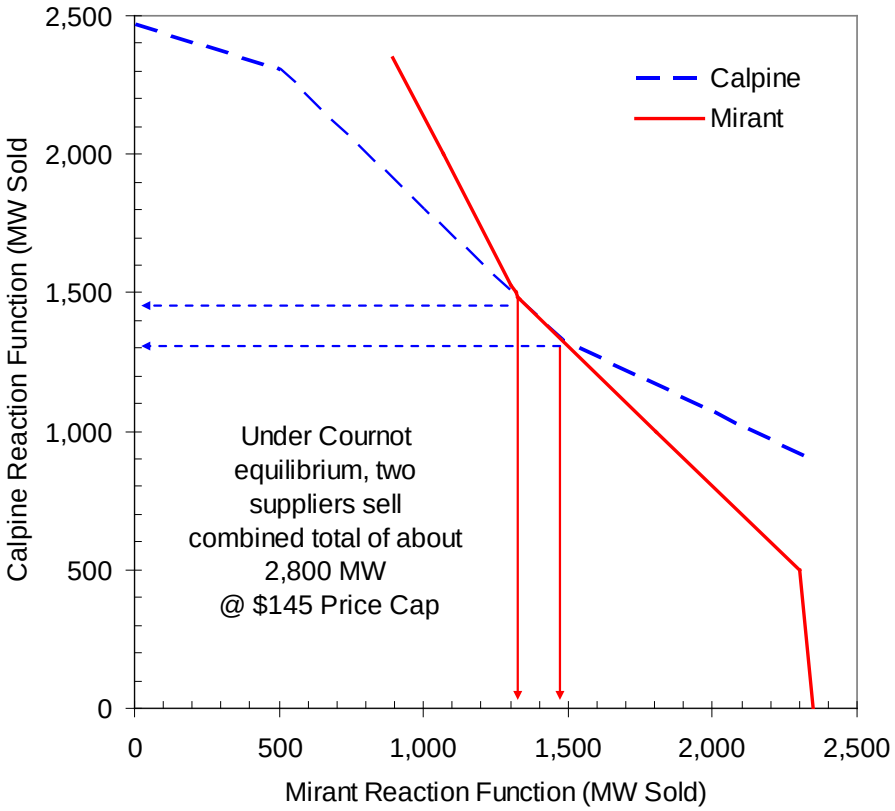


Figure 7. Local Capacity Market Outcomes under Duopolistic Bidding Scenario

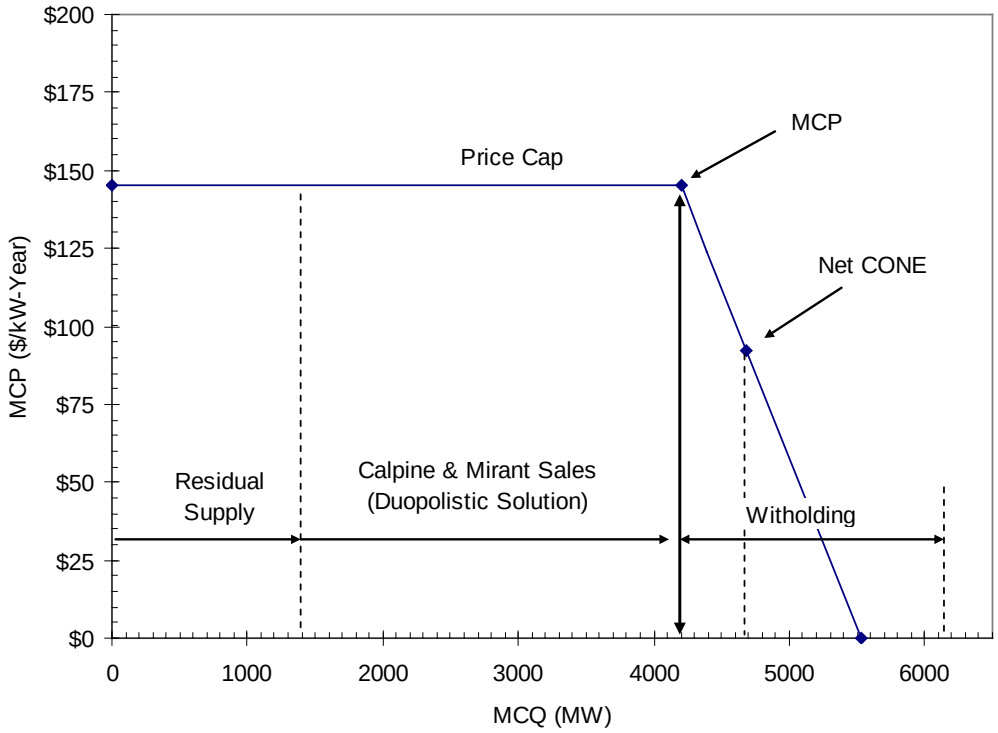


Figure 8. Reaction Functions of Two Largest Suppliers
350 MW of New Supply in Bay Area

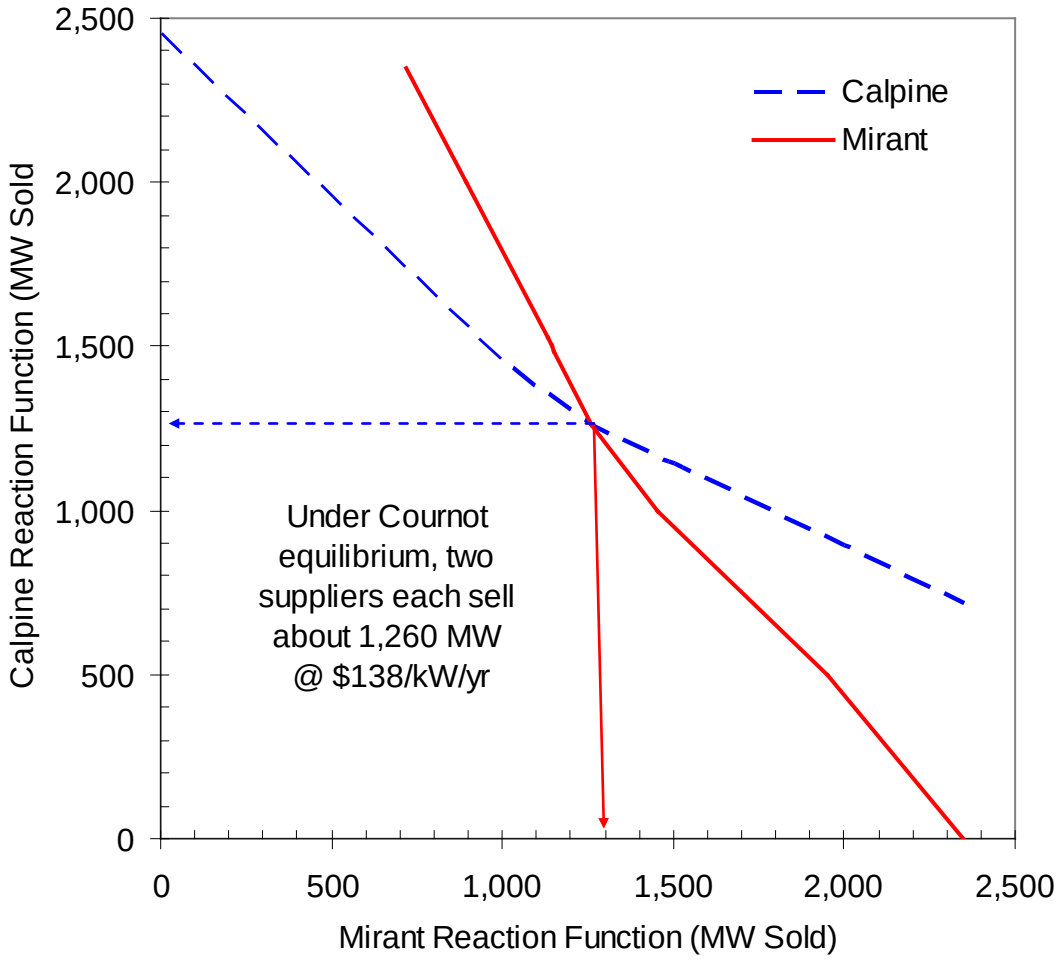
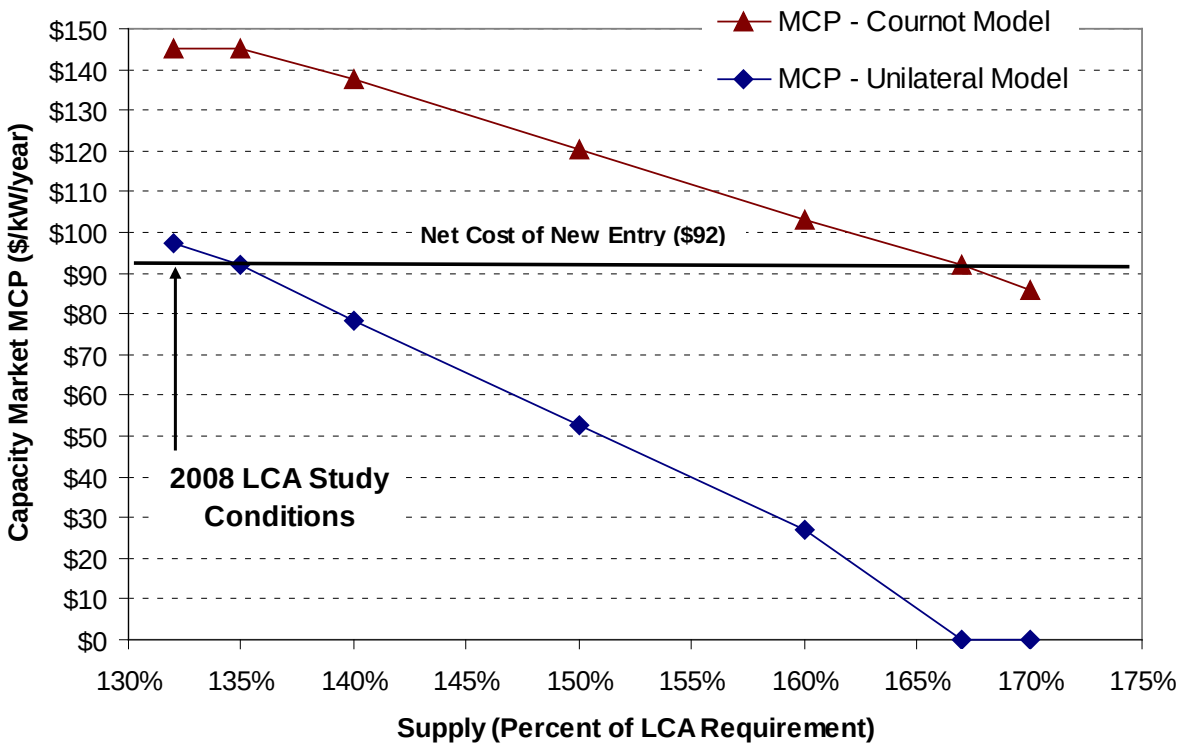


Table 6. Comparative Analysis of Potential Local Market Power in Bay Area Unilateral and Cournot Approaches

		Market Shares		Unilateral Approach		Cournot Approach	
	Supply Margin	Calpine	Mirant	MCP	% Net CONE	MCP	% Net CONE
2008 LCA Study	132%	41%	38%	$98	106%	$145	158%
100 MW of New Supply	**135%**	**39%**	**37%**	**$92**	**100%**	**$145**	**158%**
350 MW of New Supply	140%	38%	36%	$78	85%	$138	150%
825 MW of New Supply	150%	35%	33%	$53	57%	$120	131%
1,300 MW of New Supply	160%	33%	31%	$27	30%	$103	112%
1,610 MW of New Supply	**167%**	**32%**	**30%**	**$ 0**	**0%**	**$ 92**	**100%**
1,775 MW of New Supply	170%	31%	30%	$ 0	0%	$ 86	93%

Figure 9. Comparative Analysis of Potential Local Market Power in Bay Area Unilateral and Cournot Approaches



As shown in Table 6 and Figure 9, results of this comparative analysis show that in the Bay Area, despite the relatively large level of supply currently available to meet 2008 capacity requirements in the Bay Area (132%), the potential for local market power may be significantly higher due to the relatively large portion of supply owned by the two largest suppliers.

- From the perspective of unilateral market power, the addition of a very small amount of new capacity (100 MW) would make the unilaterally optimal capacity MCP drop to the net CONE ($92/kW/year). However, under the assumption of duopolistic market behavior, the capacity MCP would continue to clear at the price cap of $145/kW/year under this scenario.

- Under the assumption of duopolistic market behavior, about 1,610 MW of new supply would be needed before the capacity MCP would clear at the net CONE of $92/kW/year. This represents an increase in the level of supply from the current level of 132% of local capacity requirements to a level of 167% of local capacity requirements.

These results further illustrate how it may be inefficient or insufficient to rely on competition from potential new resources to mitigate the market power of existing suppliers within areas of the CAISO grid. In addition, these results illustrate that within areas where two suppliers each control a relatively large share of existing supply, simple techniques for assessing unilateral market power (e.g., pivotal supplier tests) may significantly underestimate the potential for local market power.[25]

III. Direct Bid and Price Mitigation

Economic Withholding

The CFCMA proposal would mitigate local market power of existing resources through direct bid mitigation in a manner that is similar to current capacity market rules in effect in New England and PJM. Under the CFCMA proposal for a centralized capacity market in California, local market power of existing resources would be mitigated through a series of specific *structural*, *conduct* and *impact* tests as follows:

- First, the CAISO would determine if the entity's bid price for any of its existing resources was above 60% of Net CONE. If not, no further screens or bid mitigation would be applied to the entity's bid. Thus, any bid at or below 60% of Net CONE is within a "safe harbor" for existing resources.
- If the entity's bid price for any of its existing resources was above 60% of Net CONE, the CAISO would determine if an entity (a) controls 20% or more of the uncommitted capacity within the Local Area, or (b) is pivotal with respect to the uncommitted capacity available to meet the local requirement.

[25] The Cournot approach applied to assess local market power in the Bay Area was also applied to the San Diego area, where the second largest supplier also controls a relatively high portion of supply (24%). However, results of this analysis showed that the capacity MCPs under the Cournot approach would be the same as the MCPs resulting from the unilateral approach, as summarized in Table 2.

- If the participant failed either one of these structural tests, the participant would then be required to submit calculations of a Net Avoidable Cost Rate (Net ACR).[26]

- If an offer exceeds the Net ACR, as determined by the CAISO's market monitor based on its review of the participant's ACR filing, the Primary Auction is run with and without bid mitigation (e.g., first using the CAISO's calculation of Net ACR, and then with the participant bid price). If the impact of mitigating the participant's bid is to lower the capacity MCP by 5% or more within any area, then the capacity MCP is set using the mitigated bids in the affected areas.
- The participant can contest the decision of the market monitor at FERC, in conjunction with a pre-auction report that the CAISO would file with the Commission.

Under this approach, within areas where there are sufficient existing resources to meet reliability requirements, the capacity MCP would presumably clear at no more than 5% above the highest Net ACR of existing capacity needed to meet demand.[27] However, if new capacity was needed to meet local requirements, the capacity MCP would be set to the lowest cost bid for the incremental amount of new capacity needed to meet requirements, subject to an overall cap of 1.4 net CONE.

The various "bright line" tests for locational market power within local areas included in the CFCMA proposal appear to provide a reasonable framework for local market power mitigation. However, DMM has noted that the CFCMA proposal calls for the CAISO's market monitor to play a very significant role in the capacity market. Under both the demand curve and CFCMA approach the CAISO must estimate Net CONE. However, as described above, the CAISO's market monitor must be prepared to perform extensive reviews of Net ACR calculations, develop and support alternative calculations as needed, and possibly defend these calculations in regulatory proceedings before FERC. In practice, this would require the market monitor to expand its internal resources to include staff with the necessary skills to perform these activities, and/or to contract and manage consultants with expertise in these areas.

Physical Withholding

In addition to mitigating the exercise of local market power through economic withholding, capacity market rules must prevent the exercise of local market power through physical withholding (i.e., simply not offering all available capacity in the auction). The demand curve approach proposed by Constellation appears to rely virtually entirely on the slope of the demand curve to deter both physical and economic withholding, without any specific provisions to

[26] Since bid mitigation is designed to reflect bidding under competitive market conditions, the CAISO assumes that the Net ACR is designed to represent a unit's projected net going forward fixed costs (excluding sunk costs). However, the CFCMA proposal indicates that the Net ACR would include "on-going capital expenses". Thus, further clarification should be provided on what capital expenses would be included in the Net ACR calculation.

[27] This also assumes that all existing capacity is bid and/or counted toward meeting local requirements through the provisions to deter physical withholding and to count capacity under export contract toward meeting local requirements included in the CFCMA proposal (see C.1, p.5 and C.5, p.7) These provisions are discussed in another section of these comments.

address physical withholding.[28] For example, Constellation's proposal states that "The CAISO conducts a demand curve clearing auction in which any uncommitted capacity may offer to sell its capacity for the coming months " (#5, p.4).

Meanwhile, the CFCMA proposal includes a strong provision that deters physical withholding by existing suppliers within local areas. Specifically, the CFCMA proposal states that:

> Existing resources must offer their capacity into the CFCM or provide notice of administrative de-listing due to unit retirement or an export contract to ensure that all resources on the CAISO system are accounted for. (C.1, p.5)

In addition, the CFCMA includes another provision which ensures that any capacity committed under bilateral export contracts can still meet local reliability needs:

> If a resource within a Local Area de-lists for export purposes, its capacity will count towards the applicable Local Area Requirement but not the statewide Resource Adequacy Requirement, and the exporting resource must offer in the CAISO markets any energy not exported. (C.5, p.7)

This provision reflects the fact that local reliability requirements are met as long as a unit is scheduled and operates to provide energy, even if that energy is ultimately scheduled for export from the CAISO system.[29]

Experience with Direct Bid Mitigation in Other ISOs

Although the ISO New England (ISO-NE) and PJM rely on the type of direct mitigation incorporated in the CFCMA proposal, it does not appear that the capacity markets of these other ISOs have incorporated locational capacity requirements to the degree that would be necessary in California to meet local capacity requirements for the CAISO's major LCAs through a capacity auction.

The capacity market design of the ISO-NE combines system direct bid mitigation with a fixed system level capacity demand requirement, similar to that incorporated in the CFCMA proposal. ISO-NE's design allows for the procurement of minimum capacity requirements for separate locally transmission constrained Capacity Zones, including Connecticut and the NEMA/Boston

---

[28] In workshop comments, Constellation appeared to also suggest that physical withholding would be deterred by FERC market rules prohibiting manipulation or anti-trust laws. As previously noted, DMM does not believe that reliance should be placed on this form of enforcement action by FERC or other legal or regulatory entities.

[29] This "must-offer" requirement that would be established under the CFCMA proposal is analogous to provisions of the current Reliability Must Run (RMR) Condition 1 type contract, which allows unit owners to contract and sell energy through bilateral transactions, but also allows the CAISO to commit and dispatch any capacity that is not scheduled to meet a bilateral sale. This requirement promotes efficiency by recognizing that a unit meets local reliability requirements even if the unit is scheduled to meet an export schedule, and prevents potential exclusion or withholding of existing supply from local capacity auctions through export contracts. While the general provision outlined in Section C.5 of the CFCMA appears to provide an effective framework for treatment of export contracts and local reliability requirements, additional details would need to be developed to clarify the nature and timing of the "must-offer" requirement applicable to these units. For example, in order to meet local reliability requirements, long start units would need to offer capacity in the Day Ahead IFM market.

Area. However, in the ISO-NE's most recent two capacity auctions, ISO-NE determined that sufficient supply was available within these capacity zones so that they were not modeled separately, and were simply cleared as part of the overall system capacity market.[30] Nevertheless, it appears ISO-NE's local auction was largely successful in meeting local reliability requirements while mitigating any potential local market power. In ISO-NE's auction for the 2010/2011 year, only about 330 MW of additional capacity needed to be procured after the auction to meet reliability requirements under ISO-NE's "backstop" authority.[31] In the auction for the 2011/2012 year, only about 342 MW of existing capacity applied to be "de-listed", with 337 MW of this being accepted after review by the market monitor.[32]

In PJM, capacity markets include four regions. However, it appears that the regions incorporated in PJM's auction are relatively broad compared to the main three load pockets in California. Results of recent auctions in PJM do indicate that PJM's capacity market has provided an incentive for the location of additional capacity in the most constrained regions of the PJM system. Specifically, prices in Local Demand Areas (LDAs) were initially relatively high compared the rest of the PJM system, but have subsequently converged toward the cost of new capacity on a system-wide level.[33]

IV. CONCLUSIONS

Analysis of NYISO-Style Demand Curve Approach

Results of the analysis presented in Section II illustrate several implications concerning the development of a capacity market in California:

- Although local market power mitigation may be lessened to some degree by investment in new resources within load pockets, relying on such capacity additions may be an ineffective or very inefficient means of mitigating the local market power within the CAISO's major load pockets. In practice, significant barriers to entry for new supply are likely to exist in these areas due to various environmental and local permitting requirements and restrictions. To the extent that new capacity may be added in these areas, much of this capacity may be from re-powering of existing supply (e.g., as part of steps needed to comply with new regulation restricting once-through-cooling), rather than entry of new supply by other entities.

---

[30] *Informational Filing for Qualification in the Forward Capacity Market*, ISO New England, ER-08-, November 6, 2007, p.10 (http://www.iso-ne.com/regulatory/ferc/filings/2007/nov/er08-190-000_11-06-7_informational_filing.pdf) and *Informational filing for Qualification in the Forward Capacity Market*, ISO New England, ER-08-, September 9, 2008, p.9 (http://www.iso-ne.com/regulatory/ferc/filings/2008/sep/er08-1513-000_09-09-08_fca_info_filing.pdf)

[31] *Forward Capacity Market Results Filing*, ISO New England, ER-08-, March 3, 2008, p.5 (http://www.iso-ne.com/regulatory/ferc/filings/2008/mar/er08-633-000_03-03-08_fca_results_filing.pdf

[32] *Informational filing for Qualification in the Forward Capacity Market*, ISO New England, ER-08-, September 9, 2008, p.14 (http://www.iso-ne.com/regulatory/ferc/filings/2008/sep/er08-1513-000_09-09-08_fca_info_filing.pdf) ne.com/regulatory/ferc/filings/2008/sep/er08-1513-000_09-09-08_fca_info_filing.pdf

[33] *Review of PJM's Reliability Pricing Model*, The Brattle Group, June 20, 2008, pp. 14-16.

- Even if significant amounts of new capacity could be added in these areas, due to the relatively high portion of existing supply owned by one or two suppliers in these areas, the level of new supply needed to ensure competitive outcomes under the demand curve approach would result in total supply levels greatly exceeding actual local capacity requirements. Since the cost of new capacity in these LCAs is likely to exceed the cost of supply in less constrained areas, this approach may significantly increase the overall costs of new capacity needed to meet CAISO system and local reliability needs.

- Within areas where two suppliers each control a relatively large share of existing supply – such as the Bay Area – commonly used techniques for assessing unilateral market power (such as pivotal supplier tests) may significantly underestimate the potential for local market power under the demand curve approach. As shown by the simple Cournot approach used in this analysis, the potential for significant local market power may exist when more commonly used analyses or tests of unilateral market power suggest that the demand curve approach would result in competitive outcomes.

Direct Mitigation of Economic and Physical Withholding

Some of the concerns about the NYISO-style demand curve approach illustrated in this paper could be lessened by modifying this approach to include strong provisions to prevent economic and physical withholding, such as those included in the CFCMA and the capacity markets of ISO-NE and PJM. For instance, economic withholding by major suppliers deemed to have market power might be addressed by requiring this capacity to be bid at mitigated prices reflecting their net going forward fixed cost, while physical withholding might be addressed by requiring that existing capacity participate in the centralized capacity market unless it can justify a decision to retire or mothball the unit for economic or other factors.

Such more direct provisions to prevent economic and physical withholding are likely to more effectively mitigate local market power than a NYISO-style demand curve approach, without relying heavily on investment in additional new supply well beyond levels that would be economically efficient or needed to meet actual local capacity requirements. Under the CFCMA approach, when existing supplies exceed local capacity requirements, local capacity market prices would presumably not clear above the net cost of new supply at a system level.[34] However, if new supply is needed within an LCA to meet actual local capacity requirements, local capacity market prices would presumably clear at the net cost of new supply within the LCA. In comparison to the range of prices that may result under the demand curve approach, such capacity prices would appear to effectively mitigate local market power, while still providing efficient signals for investment in new supply within LCAs as such additions are needed.

[34] This assumes that the net going forward fixed cost (net GFFC) of existing supply is less than the net cost of new supply on a system level. In this case, if new supply is actually needed at a system level, local capacity market prices would presumably clear at the net cost of this new supply. If no new supply was needed at the system or local level, local capacity prices would presumably clear at the higher of 60% of net CONE or the net GFFC of existing supply within local areas.

Other Challenges in the Design of Local Capacity Markets

Finally, as DMM has noted throughout the discussions of a centralized capacity market in California, additional analysis is needed of how specific capacity requirements may be established for some of the CAISO's local areas, such as the Bay Area and Western LA Basin. In these areas, local reliability studies show that different various layers of reliability constraints and sub-area requirements exist. In addition, different generating units can have dramatically different effectiveness factors at meeting these different dimensions of local reliability requirements. However, in the context of the type of centralized capacity auction being proposed in California, it appears that each LCA would need to be defined using a single fixed capacity requirement, with each MW from each generating unit being considered to be equally effective at meeting minimum local capacity requirements.

This creates a potential gap or inefficiency from the perspective of a capacity market design. On one hand, if these different dimensions of local reliability requirements are ignored, auction results based on a fixed capacity requirement may be highly inefficient (i.e., more capacity may be procured that is actually required), or the CAISO may need to rely on backstop contracting ability to meet any local reliability requirements not met through the mix of resources selected in the auction based solely on price. On the other hand, incorporating these various sub-area constraints into local capacity market requirements would make auction results more susceptible to the exercise of local market power. While the more direct mitigation of economic and physical withholding incorporated in the CFCMA proposal appears to be better suited to mitigate local market power that exists due to these various sub-area constraints, further refinement of how these localized constraints are incorporated in to local capacity requirements and the local market power tests in the CFCMA proposal appear be necessary to ensure that local requirements can be met an efficiently and effectively through a centralized capacity market.