Opinion on the Necessity of Effective Local Market Power Mitigation for a Workably Competitive Wholesale Market

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1. Introduction

The most glaring weakness in the currently operating California Independent System Operator (CAISO) market design is the lack of an effective local market power mitigation (LMPM) mechanism. The purpose of this opinion is to characterize the determinants of local market power and why they are common to all congestion pricing methods, including Locational Marginal Pricing (LMP). We then describe a set of criteria for evaluating LMPM mechanisms. We then propose an LMPM mechanism for the California market that satisfies these criteria. Finally, we compare this LMPM mechanism to the Automatic Mitigation Procedures (AMP) for local market power mitigation that currently exist in New York and New England and the LMPM procedure currently in use in the PJM market.

If the MD02 process is to be successful, the CAISO must obtain the authority from the Federal Energy Regulatory Commission (FERC) to implement an effective LMPM mechanism. Although this sort of LMPM mechanism will not guarantee the success of the MD02 process, it is an important part of the package. Combining effective LMPM with substantial forward contracting between suppliers and load-serving entities, as well as active participation in the wholesale market by end-use consumers will provide strong incentives for workably competitive wholesale market outcomes.

The extent of forward contracting and active demand-side participation in the wholesale market are both under the control of the California authorities, in particular the California Public Utilities Commission (PUC). However, the authority for the ISO to implement an effective LMPM mechanism must be obtained from FERC. Therefore, the MD02 process should focus on obtaining the most important aspect of a successful wholesale market design that is not under the control of California parties—an effective LMPM mechanism. The MD02 process should devote the utmost attention to designing a LMPM mechanism that recognizes the causes and consequences of local market power, and mitigates it in a manner that improves, rather than detracts from, market performance.

2. Causes and Consequences of Local Market Power

The causes of local market power are well known. Transmission and other network constraints sometimes dictate that, in order to maintain system reliability, at least some power *must* come from a specific unit or set of units. Because of these constraints, these units face little or no competition for the supply of these services. Particularly, around large population centers and in geographically remote areas, there are often only a small number of generation units able to meet a local energy or reserve capacity need. Often all of these units are owned by the same firm. Local market power is a problem that is found in every electric system. It is important to note that the problem exists *regardless* of the methods used to price transmission congestion, be they zonal methods, flow-gate methods, or LMP.

The primary consequence of these situations is that absent mitigation units with local market power would be able to extract substantial, practically unlimited, profits from the market for the output from those units. A secondary, somewhat less obvious consequence lies in the impact of this local market power on the broader market. Knowing that there is a chance that a portion of a unit's output must be taken, the owner will bid that output less aggressively into the market than it otherwise would. Other firms, knowing that their competitors are likely to compete less aggressively, will also find it profitable to bid less aggressively. This creates a process of negative feedback that can lead to higher prices throughout the entire region. Many of the difficulties encountered in dealing with the local market power problem arise because of this interface between regulated and market-based services. One of the attributes of effective LMPM that we discuss below is therefore the separation, wherever possible, of regulated "local" service from the other market-based services.

All of these realities of system operation in the wholesale market regime make it essential that the CAISO have a transparent mechanism to mitigate local market power. This mechanism would mitigate local market power without distorting the prices paid to generating units that do not possess local market power. It should also provide the strongest possible incentives for all generation unit owners to bid as close as possible to their minimum marginal cost of supply during all system conditions.

3. Criteria for Designing Local Market Power Mitigation (LMPM) Mechanism

The primary goal of LMPM is first, to limit the ability of a supplier to exercise local market power and second, to limit the impact of that local market power *and the regulations intended to deal with it* on the broader market. This includes limiting the ability of a supplier to use some units in its portfolio that possess local market power to increase the price received by other units in its portfolio. These goals for local market power mitigation lead us to propose the following criteria for evaluating LMPM mechanisms.

Subject all units to prospective LMPM rather than designate a subset as LMPM units. Because of the large number of factors that become known just before real-time system operation, it is very difficult to predict far in advance of day-ahead system operation whether a supplier possesses substantial local market power. Because of this, designating a subset of generation units for the provision of LMPM services as reliability must-run (RMR) units will miss many instances when other generation units possess substantial local market power. More important, such a distinction between generation units will create strong incentives for suppliers to operate (or fail to operate) their RMR units to enhance the ability of their non-RMR units to exercise local market power. The AES/Williams case in California is a well-known example of this phenomenon.[1]

Depending on system conditions—the level and geographic distribution of demand, amount of available transmission capacity in the network, and operating condition of all units in the CAISO control area—any unit in the control area can possess substantial local market power. For this reason, a LMPM mechanism should apply to all units in the CAISO control area on a prospective basis. The Participating Generator Agreement (PGA) of each generation unit in the CAISO control area should include the requirement that the unit will be subject to mitigation if system conditions arise that endow it with substantial local market power.

Allow mitigated generating units to earn at least their incremental costs for supplying the mitigated quantity of energy. Suppliers must be paid enough to keep their units operating when the ISO needs the units for reliable system operation. If a unit must be turned on to provide local reliability energy, the unit owner should be compensated for the associated start-up and no-load costs.

Regulatory mechanisms for the recovery of fixed costs should not be allowed to impact market prices. Suppliers must be paid at least enough to keep their units operating when the ISO needs the units for reliable system operation. However, consistent with the goal of introducing wholesale competition in electricity supply, the primary source of income for fixed cost recovery should be sales of energy and ancillary services at market prices under conditions when the unit is not subject to mitigation.[2] To the extent units are unable to recover their going forward fixed costs through market sales, the owner should elect a cost-of-service option to provide for the recovery of these costs.

Further, variable payments for LMPM services that are in excess of incremental costs can increase the frequency that mitigation occurs and reduce market efficiency**.** Overly generous LMPM mechanisms effectively amount to allowing suppliers to exercise local market power. Moreover, making it financially attractive for generation units to be subject to LMPM makes it more likely that suppliers will schedule their units in a manner that causes conditions that subject their units to local market power mitigation. Further, we believe that LMPM should provide incentives to divest and eliminate local market power problems; overly generous LMPM payments would provide the opposite incentive. Therefore, a LMPM mechanism should pay suppliers enough to keep their units on line (if the ISO needs the units for reliable system operation), but not enough to

[1] ORDER APPROVING STIPULATION AND CONSENT AGREEMENT, AES Southland, Inc. and Williams Energy Marketing & Trading Company, Docket No. IN01-3-001, (Issued April 30, 2001)

[2] In contrast to the PJM market, the California ISO pays $/MW market determined prices for the provision of non-spinning reserves and replacement reserves. These ancillary services payments are typically earned by high cost peaking units that might not be able to make sufficient revenues from selling energy to cover their fixed costs. For these high cost units, ancillary services revenues make a substantial contribution to fixed cost recovery.

make it financially attractive for the supplier to be subject to local market power mitigation.

Scarcity rents should be paid only when there is scarcity. As described above, generation units must have the opportunity to earn revenues above their incremental costs if they are to recover their fixed costs. In particular, if a condition of scarcity arises in a specific location, prices in that location should rise above the incremental costs of all the units in that location. The Combustion Turbine Proxy Price (CT-Proxy Price) that has been recently adopted in the ISO-New England market is intended to produce such an outcome by allowing peaking generation plants to bid prices well above their incremental costs. As the FERC recognized, however, "this may give generators an incentive to depart from a competitive marginal cost bidding strategy." More seriously, such incentives raise the prospect that bids from all units in a portfolio may be impacted, allowing a mechanism intended to deal with scarcity in a given location to spillover into the broader market. A much better option is to let prices rise above incremental costs in conditions of scarcity without requiring generators to bid at those levels.

One way to achieve this is to allow the LMP at a given location to rise to a level set by demand bids (or, absent demand bids, to the price cap) when the capacity from all supply bids are exhausted. Consequently, if there is insufficient energy available to meet all demand bid in at or above the price cap at that location in the transmission network, the LMP at that location would automatically be set equal to the price cap, regardless of the highest-priced supply bid accepted. If this scarcity condition occurs frequently, appropriately designed energy and ancillary service markets would provide ample incentive for new generation investment. It should be noted, however, that a scarcity of bid supply does not necessarily reflect a true scarcity of available capacity. Mechanisms such as forward financial contracts and other spot price hedging agreements that allow spot prices to rise to scarcity levels must be combined with mechanisms that mitigate the ability of firms to withhold capacity and induce artificial scarcity.

We would like to emphasize that there are circumstances when high prices may not and should not be allowed to provide incentives for new investment. If there is sufficient generation in a local area to meet demand, but all of it is owned by a single firm, setting high prices at that location may trigger unnecessary new investment by others. In contrast, if there are a number of competing suppliers at that location, but insufficient capacity to meet demand, then setting a high price at that location should trigger the needed new investment. Consequently, high local prices due to scarcity conditions should motivate new entry, but high prices due to local market power may not trigger new investment and should not be allowed to occur because they can lead to inefficient new investment.

Regulated bids distort prices. Such distortions should be minimized. Mitigated bids can be allowed to influence market prices if there is substantial evidence that they closely approximate the minimum incremental costs of production. In general, treating a regulated marginal cost of supply as if it were the unit's minimum cost of supply implies the existence of a perfect regulatory process, something that is well known not to exist. For example, if a near-perfect regulatory process existed, there would be little need for introducing competition in wholesale electricity supply, because the regulatory process would find the minimum cost method of supplying electricity. In the more likely case that regulated costs diverge from minimum incremental supply costs, allowing such bids to affect prices received by other generators can diminish system efficiency and exacerbate market power. Effective LMPM must distinguish between services that can *only* be provided at a regulated price versus those that can be paid a price determined through a market mechanism. Wherever possible, these two services should be priced separately. Otherwise suppliers will have an incentive to leverage market power possessed by one unit to all other units in their portfolio. This is accomplished by withholding lower cost units from the market or bidding high prices in order to increase the frequency that units with high mitigated bids set market prices earned by all units in the supplier's portfolio. Thus, artificially high mitigated bids can significantly exacerbate existing system-wide or zonal market power problems if those bids frequently affect market prices.

Of particular concern are mechanisms that allow cost-based bids with adders or a CT-Proxy price to set LMPs. Administratively determined payments introduce distortions in market prices. These mechanisms are in part motivated by the need to pay scarcity prices to suppliers. As discussed above, none of these regulated bids equal what the unit owner would bid if it faced substantial competition from other suppliers. Therefore, allowing these regulated bids to enter the price-setting process can result in distorted price signals at that unit's location. In addition, because the LMP at a given location in the transmission network is equal to the increase in system-wide bid-in costs associated with serving one more unit of demand at that location in the network, allowing these mitigated bids to enter the LMP process can distort the prices at other locations in the network.

Units needed by the ISO but unable to recover their fixed costs from revenues earned during non-mitigated hours should be offered a cost-of-service option. If a unit is mitigated so frequently that the owner cannot recover sufficient revenues from selling energy during non-mitigated hours to recover its fixed costs, then the unit owner should be offered a cost-of-service option that pays both its variable costs and annual fixed costs. However, these units should not be eligible to participate in any ISO markets for the duration of their cost-of-service contract with the ISO. Moreover, if a unit owner applies for a cost-of-service contract it puts itself at risk for the ISO turning it down and then it has the choice to exit the industry or continue to operate under the ISO's PGA which requires the unit owner to be subject to the ISO's prospective LMPM mechanism.

This criterion does not rule out the possibility of a load-serving entity signing a long-term contract with some local generator to provide local energy at some maximum price, similar to the existing RMR contracts signed by the ISO. The existence of a full cost-of-service option for the local generator, should it be needed for reliability reasons, provides a regulatory backstop on the contract terms that this local generation unit owner can get from the local supplier. For example, if the local unit owner knows that the CAISO needs this unit for reliability reasons, then it would be willing to sign such a contract if it believed that the unit would earn higher economic profits than it would earn under the cost-of-service alternative. Such a scheme would eliminate the need for the

CAISO to engage in costly and time-consuming RMR contract renegotiations. Both the load-serving entities and local unit owners would be aware of the cost-of-service alternative that prevents the exercise of the local market power by the unit owner, and they could negotiate a mutually beneficial contract under these conditions.

4. Recommended Local Market Power Mitigation Mechanism

This section devises a local market power mitigation mechanism that addresses the issues raised in the previous section. There are three basic dimensions to the design of a LMPM mechanism. The first is how to determine whether a supplier possesses significant local market power. The second is the payment received by a supplier when they have been mitigated. The third element is how LMPs should be calculated when some suppliers have triggered the LMPM mechanism.

Consistent with discussion in the previous section, the mitigation mechanism should apply to all units in the California ISO control area. Ideally, the PGA that each supplier signs with the California ISO would allow it to sell at market-based prices, but would also subject the supplier to the California ISO local market power mitigation mechanism. This would eliminate the need for RMR contracts. For this reason, all existing RMR contracts should be allowed to expire. If a firm would like to retire a unit because it is unable to recover its going-forward fixed costs under these conditions, but the ISO still needs it for local reliability energy, the unit owner would be required to file a cost-of-service contract with the FERC. This unit would then be guaranteed cost recovery for the year in exchange for operating whenever the ISO needs the unit to operate. In addition, this unit would not be allowed to sell at market-based rates in any California market.

Determining Whether a Supplier Possesses Substantial Local Market Power

There are a variety of mechanisms for determining whether a supplier possesses substantial local market power. What is most important is selecting a mechanism that is as transparent as possible to market participants while dealing with the fundamental causes of local market power we identified in Section 2. One approach is to mitigate all of a supplier's pivotal supply.[3] Pivotal supply is defined as output that is needed to meet demand given the bids submitted by its competitors. This condition could be modified to a pivotal duopoly condition. In that case, suppliers would possess local market power if a duopoly composed of any two suppliers were pivotal. Another approach is the 'PJM-style' method to making this determination, which first pre-specifies certain transmission interfaces as competitive. All other transmission interfaces would be designated as non-competitive. Then, suppliers that bid to relieve congestion on these latter, non-competitive interfaces are deemed to possess local market power. Even though there are many plausible ways to make this determination, the fundamental determinant of whether

[3] For additional information, see "Affidavit of Frank A. Wolak on behalf of the Electricity Consumer Resource Council, The Transmission Dependent Utility Systems, Buckeye Power, Inc., Great River Energy, Wolverine Power Supply Cooperative, Inc., and East Texas Electric Cooperative, Inc." filed at Federal Regulatory Commission in Docket No. RM01-12-000, November 11, 2002, available from http://www.stanford.edu/~wolak. For a similar proposal, see M. Rothkopf, "Control of Market Power in Electricity Auctions," The Electricity Journal, Oct. 2002.

a supplier possesses significant market power is the following: that there is a high likelihood that this supplier can raise the price it receives for selling electricity from some or all of it units through how it bids or schedules its units because it faces insufficient competition to supply energy. This definition also applies specifically to local market power, taking into consideration transmission congestion and local reliability constraints.

The determination of whether a supplier possesses significant market power is the same as saying that a supplier faces too little competition from other suppliers for a market mechanism to be relied upon to set the prices paid to suppliers for their output. The PJM approach relies on the ISO making a determination far in advance of system operation about which transmission interfaces have a large enough number of suppliers competing to use it and, thus, a market mechanism can be used to set prices on either side of the interface. We prefer the use of a pivotal supplier concept because we do not believe it is possible to determine in advance when a supplier or group of suppliers possesses local market power. A pre-commitment on the part of the ISO to mitigate the pivotal quantity of energy and reserve capacity when a supplier is pivotal protects against unanticipated conditions in the transmission network under which suppliers can exercise local market power.

Payments for Mitigated Suppliers

As discussed in Section 3, suppliers should at a minimum be allowed to recover the incremental costs associated with providing energy or ancillary services from the portion of their unit that is subject to mitigation. If the nodal price exceeds the mitigated bid price, then the mitigated supplier should be allowed to receive that price, which would make some contribution towards the unit's fixed costs. However, paying for the recovery of fixed costs through a variable (*i.e.* $/MWh) payment can distort not only the incentives of the firm receiving the payment, but also market prices throughout the network. To the extent that the fixed costs of a "must-run" plant needs to be subsidized, this subsidy should take the form of a fixed payment that does not distort market prices. Recovering fixed costs in a per MWh payment creates the same leveraging of local market problem that existed in California under the original Contract A RMR contracts. These contracts paid RMR unit owners their variable cost plus a portion of their annual fixed costs for each MWh of local reliability energy they provided. Because some of these units were only expected to run less than 500 hours per year, a number of these RMR variable payments were substantially higher than market prices during most hours of 1998. The variable payment created an opportunity cost that the RMR Contract A unit owner could bid into the California Power Exchange (CalPX) during hours when the owner was confident the RMR unit would be needed to provide local reliability energy. Because the owner was virtually certain this unit would be called to provide RMR energy, there was no downside for the owner to bid this RMR variable payment into the CalPX, because if it were accepted, it would set the price earned by all of the supplier's units.[4] The Federal Energy Regulatory Commission recognized this leveraging problem

[4] Bushnell, James and Wolak, Frank, (1999) "Regulation and Leverage of Local Market Power in the California Electricity Market," (available from http://www.stanford.edu/~wolak) discusses this problem in detail and quantifies the magnitude of market inefficiencies that resulted from the existence of fixed cost recovery in the original Contract A form of the California ISO's RMR contracts.

and revised the Contract A RMR contracts to have an annual fixed payment and a variable cost payment when the unit is required for local reliability energy. This same potential for leveraging exists in an LMPM mechanism that includes fixed cost recovery in the regulated bids of mitigated suppliers.

Calculating Market Prices When Some Suppliers Have Been Mitigated

Some of Section 3's discussion was devoted to showing that distorted market prices could result from allowing bids, particularly those containing arbitrary adders or proxy prices, to enter the LMP process. These LMP pricing distortions can be substantial and are largely unnecessary. It is unlikely that all units in any supplier's portfolio will be pivotal. When a supplier is pivotal, usually this pivotal status applies only to a small fraction of its capacity. It is only this pivotal fraction that is truly 'must-run' and therefore in need of mitigation. For the vast majority of system conditions, we expect that the total quantity of pre-dispatched RMR energy in the California ISO system to be an upper bound on the total pivotal quantity in the system.[5] Because these pivotal quantities can be thought of as 'infra-marginal,' the remaining, non-mitigated supply should be left to set prices that are undistorted by this regulation.

Consequently, we propose that suppliers be required to offer at mitigated prices their pivotal quantity into the day-ahead energy market in a process similar to the current RMR pre-dispatch mechanism. For any energy beyond this pivotal quantity the supplier should be free to bid whatever the supplier would like, and the LMP mechanism would operate with these modified bid curves. The implicit assumption in this LMPM mechanism is that there is effective competition among suppliers for this additional energy or capacity. Consequently, a market mechanism can be used to set these prices.

The setting of the mitigated bid level for the must-run quantity presents a set of trade-offs. The options, broadly, include (1) requiring the entire pivotal quantity be entered into the market as a price-taker, (2) requiring it be offered to the market at a regulated incremental cost, or (3) entering it into the market at a regulated incremental cost plus some administratively determined adder. Starting with the last, we strongly urge that adders intended to allow for the recovery of fixed costs or the provision of investment incentives *not* be allowed to impact market prices.

Moving to the first two options, we note that requiring the pivotal quantity to be a price-taker has the benefit that the ISO is assured that the pivotal quantity of energy will be taken in the day-ahead energy market. The ISO knows as of the start of the day-ahead market that it needs this mitigated quantity from the supplier. Consequently, by eliminating the uncertainty associated with whether the required amount of energy or capacity is actually scheduled on a day-ahead basis, system reliability will be enhanced. Conversely, entering this pivotal quantity with regulated incremental cost bids creates the potential that these bids might not be accepted in the day-ahead energy market, which

[5] To see the logic underlying this statement, consider the following simple example. Suppose there are ten firms each of which own 1 MW and demand is 9.5 MWh. For this demand level, the sum of all pivotal quantities across all ten suppliers is 5 MW. If demand falls below 9 MWh, then the sum of all pivotal quantities across all ten suppliers is equal zero.

makes very little sense given that this amount of energy is required from the supplier or the system cannot operate in real-time. We also note that cost-of-service regulated payments seriously curtail a firm's incentive to reduce costs. To the extent that regulated payments are allowed to set market prices, the adverse incentive effects can be even stronger. Requiring suppliers with local market power to be price-takers for only the pivotal quantity of energy they supply has the advantage of creating a clear distinction between a monopoly service and a service that can be provided though a market mechanism.

It is also true, however, that the degree of the regulatory distortion caused by utilizing incremental costs should be small relative to those created by the addition of administratively determined adders. Further, to the extent that a mitigated quantity is in fact marginal, incremental costs could come closer to the right answer than would a price-taking bid. The severity of the distortion will also depend upon how responsive market-participants are to the LMPs. In general, the more responsive that load, generation, and operations are to prices, the more serious are the subsequent regulatory distortions, because market participants take actions and make investment decisions based on these distorted prices.

Consequently, we strongly recommend against the inclusion of any adder or CT proxies in the mitigated bid level. We believe that requiring suppliers to act as price-takers for their mitigated quantities of energy will increase the competitiveness of the wholesale market and reduce the cost of real-time system operation. However, to the extent that the ISO is able accurately estimate incremental costs, the distortions introduced by allowing regulated incremental cost bids for mitigated quantities to enter the LMP process should be small.

5. Comparison to Other Local Market Power Mitigation Mechanisms

It is useful to compare the LMPM mechanisms currently in place in other ISOs on the basis of these criteria. There are two basic approaches to local market power mitigation among the eastern ISOs—the PJM approach and those based on modifications of the AMP mechanism. The proposal for LMPM being offered by the California ISO is based philosophically upon the mechanism employed in the PJM market. The AMP style approaches seem to be favored by FERC in their most recent decisions.

Based on California's experience with the AMP mechanism, we do not recommend AMP style approaches to local market power mitigation unless the conduct thresholds are reduced to within 10% of the unit's filed marginal cost, the impact thresholds are substantially reduced or eliminated, and an additional mechanism is used to determine whether a unit possesses local market power so that the tighter LMPM conduct and impact thresholds are applied to a unit's bids. Typically, AMP-style approaches pre-specify certain interfaces as non-competitive and implement tighter conduct tests to determine whether a supplier possesses local market power. As discussed in Section 3, this approach ignores the fact that conditions when a supplier possesses substantial local market power are difficult to predict in advance. The requirement to satisfy the usual system-wide conduct or impact test to determine whether to mitigate a supplier's bid when they possess substantial local market power also seems inappropriate. Taking the example of a pivotal supplier, by definition the firm can set the price at whatever level it would like because it is the monopolist for the pivotal quantity of energy. One would therefore expect a supplier to bid just below the levels necessary to trigger the conduct or impact tests of an AMP-like mechanism. In this sense, the conventional AMP-style approaches to LMPM amount to allowing suppliers to continue to exercise local market power, but just not too much local market power. Even if lower conduct and impact thresholds are set for an AMP-style LMPM procedure, an additional set of protocols must be devised to determine whether a supplier possess substantial local market power and these lower thresholds are applied. The pivotal supplier concept is one such method for making this determination. However, as noted above, if a supplier is pivotal then the above criticism that the AMP mechanism allows a supplier to exercise all allowable local market power still applies.

The PJM approach comes much closer to satisfying the properties of our preferred mechanism. For the purpose of local market power mitigation, the PJM control area is divided into three geographic regions. Any bids to supply energy within these regions that must be taken out of bid merit order in that region without respecting transmission constraints within that region is deemed to possess substantial local market power. All out-of-merit bids are then mitigated to some previously agreed upon level, and the locational marginal pricing mechanism is then implemented with these mitigated bids. By far the most common value for bid mitigation in the PJM ISO is variable cost plus a ten percent adder.

Although the PJM local market power mitigation mechanism accounts for the fact that all generation units in the ISO's control area can possess significant local market power, this mechanism does not completely eliminate the incentive firms with a portfolio of generation units have to exercise local market power. Because units deemed to have local market power are allowed to set prices with mitigated bids that include an administratively determined adder, this creates an incentive for suppliers that own a portfolio of units to bid and schedule these units so that high cost mitigated bids from units deemed to have local market power set market-clearing prices for as many units in the supplier's portfolio as possible. In this way the supplier may be able to leverage any local market power possessed by one or more units in its portfolio to all other units in the portfolio. This incentive to leverage local market power under the PJM local market power mechanism also creates incentives for a supplier to expand the size of its portfolio so that more units can earn the market-clearing price set by the mitigated bid of the unit possessing local market power. Wolak (2002) discusses the incentives suppliers have to leverage local market power and increase the size of their portfolio of generation units under the PJM market power mitigation mechanism.[6] We also suspect that the PJM approach to determining whether a unit possesses substantial market power will in general result in a larger quantity of mitigated bids than our preferred approach. There are two reasons for this suspicion. First, the PJM approach subjects all of the capacity of the unit determined to possess substantial local market power to mitigation, whereas our approach only subjects the pivotal quantity to mitigation. Second, it is possible that a

[6]See Note 3, *supra.*

unit taken out of merit order is not pivotal and would therefore not be mitigated under our preferred scheme.

6. Summary and Conclusions

In summary, we strongly urge the Federal Energy Regulatory Commission to allow the California ISO to implement an effective local market power mitigation mechanism along the lines described in this opinion. This mechanism should allow the ISO to phase out RMR contracts as soon as possible, but still allow sellers needed for purely reliability reasons to sign cost-of-service contracts with the ISO. To the extent that RMR-like contracts are desired by load-serving entities and generation owners, these entities should be encouraged to enter into such agreements within the LMPM framework outlined in this opinion. All market-based-price units should be subject to a prospective LMPM mechanism that mitigates their bids to supply energy when they are deemed to have local market power. A mitigated bid should not enter the locational marginal pricing process unless it can be shown to be a close approximation to the unit's minimum marginal cost of supplying energy. These suppliers can submit market-based bids for any output beyond the mitigated quantity and receive the market price for all energy sold, including the mitigated quantity of energy. A local market power mitigation scheme with these features has the greatest likelihood of leading to wholesale prices that benefit final consumers of electricity while providing suppliers with ample opportunities to earn a reasonable rate of return on their generation investments through the sale of energy and ancillary services at market prices, or bilaterally negotiated capacity and energy contracts between suppliers and load-serving entities.